THE AMERICAN ENERGY INITIATIVE, PART 12: IMPACTS OF THE ENVIRONMENTAL PROTECTION AGENCY'S NEW AND PROPOSED POWER SECTOR REGULATIONS ON ELECTRIC RELIABILITY

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

ONE HUNDRED TWELFTH CONGRESS

FIRST SESSION

SEPTEMBER 14, 2011

Serial No. 112–83

Printed for the use of the Committee on Energy and Commerce

energycommerce.house.gov

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U.S. GOVERNMENT PRINTING OFFICE

75–772 PDF WASHINGTON : 2012

For sale by the Superintendent of Documents, U.S. Government Printing Office
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C O N T E N T S

THE AMERICAN ENERGY INITIATIVE, PART 12: IMPACTS OF THE ENVIRONMENTAL PROTECTION AGENCY'S NEW AND PROPOSED POWER SECTOR REGULATIONS ON ELECTRIC RELIABILITY

WEDNESDAY, SEPTEMBER 14, 2011

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON ENERGY AND COMMERCE,
Washington, DC.

The subcommittee met, pursuant to call, at 9:19 a.m., in room 2322 of the Rayburn House Office Building, Hon. Ed Whitfield (chairman of the subcommittee) presiding.

Members present: Representatives Whitfield, Shimkus, Walden, Terry, Burgess, Bilbray, McMorris Rodgers, Olson, McKinley, Gardner, Barton, Rush, Inslee, Castor, Markey, Green, Capps, Doyle, and Waxman (ex officio).

Staff present: Charlotte Baker, Press Secretary; Ray Baum, Senior Policy Advisor/Director of Coalitions; Anita Bradley, Senior Policy Advisor to Chairman Emeritus; Maryam Brown, Chief Counsel, Energy and Power; Patrick Currier, Counsel, Energy and Power; Garrett Golding, Professional Staff Member, Energy and Power; Cory Hicks, Policy Coordinator, Energy and Power; Heidi King, Chief Economist; Mary Neumayr, Senior Energy Counsel; Katie Novaria, Legislative Clerk; Jeff Baran, Democratic Senior Counsel; Greg Dotson, Democratic Energy and Environment Staff Director; Caitlin Haberman, Democratic Policy Analyst; and Alexandra Teitz, Democratic Senior Counsel, Energy and Environment.

OPENING STATEMENT OF HON. ED WHITFIELD, A REPRESENTATIVE IN CONGRESS FROM THE COMMONWEALTH OF KENTUCKY

Mr. WHITFIELD. This hearing will come to order. This is the 12th day of our American Energy Initiative hearing, and today we are going to focus on the impact of the EPA's new and proposed power sector regulations and the reliability of the electric power grid.

The Energy Information Administration projects that electricity demand will increase 31 percent by 2035. That means new electric power plants will more than likely have to be built, and that includes all kinds of power plants. But getting EPA approval to do so was already enough of a challenge before utility MACT, new source performance standards for greenhouse gases, interstate transport, cooling towers, coal combustion residuals, and all the other new and pending regulations were added to the mix. As it is, this Administration has brought construction of new coal-fired generation to a near standstill, and things are only going to get harder as additional regulations take effect.

At the same time, existing facilities are under threat. EPA's regulations are likely to force accelerated retirements of many coal-fired plants that are still badly needed. Studies from the North American Electric Reliability Corporation and several others estimate serious risks to reliability from these retirements.

Add to that the units facing significant downtime as they are retrofit to comply with the host of new regulations, and there is genuine concern whether there will be enough electric generating capacity to meet the Nation's growing demand. The impacts of more expensive electricity are bad enough, and alone are reason to closely scrutinize the many new regulations likely to raise them. But the potential consequences of unreliable electricity, on the economy, on the military and on the lives of the American people, are even more disturbing.

We need to know the cumulative impact on reliability of all the rules that are in the works in the pipeline, which is precisely why the TRAIN Act, in our view, is so important. This is a very serious problem, but I have yet to see serious treatment of it by EPA. The agency has shown insufficient concern over the cumulative burden of its regulations as it moves ahead to implement them. This attitude of "regulate first, ask questions later" needs to end.

Nor is the EPA coordinating with the Federal Energy Regulatory Commission as well as other federal and State-level organizations responsible for the reliability of the grid. Needless to say, for EPA to embark on a regulatory agenda that threatens reliability without working closely with FERC and other federal agencies is simply unacceptable.

I know that 14 different entities have examined the potential loss of energy-producing power, and they range anywhere from almost 80 gigawatts down to 10 gigawatts, and on the preliminary assessment, the lowest prediction of retired capacity was EPA, but the mere fact that we have so many different agencies with such different views on the capacity impact certainly would illustrate that we need better coordination on this issue.

And so I look forward today to learning more from the leadership at FERC who are responsible for reliability on precisely what their views are on this issue and how comfortable they feel in assuring the American people that reliability will not be an issue.

[The prepared statement of Mr. Whitfield follows:]

Opening Statement of Chairman Ed Whitfield
Energy and Power Subcommittee
Hearing on The American Energy Initiative
September 14, 2011

This hearing will come to order. This is the 12th day of our American Energy Initiative hearing, and today we will focus on the impact of the EPA's new and proposed power sector regulations on the reliability of the electric power grid.

The Obama EPA's unprecedented regulatory agenda brings with it a number of unprecedented problems. These regulations are having a chilling effect on job growth. They threaten America's industrial competitiveness. They are also placing upward pressure on energy prices, and since many of the new requirements target electric power plants, that includes the cost of electricity.

But today we will go beyond the question of how much it will cost to turn the lights on in the years ahead and address an even more serious problem - whether we can depend on the lights to go on at all. We need much better answers to these reliability concerns than we have gotten thus far. That is the purpose of today's hearing.

The Energy Information Administration projects that electricity demand will increase 31 percent by 2035. That means new electric power plants will have to be built, and that includes coal-fired generation. But getting EPA approval to do so was already enough of a challenge before utility MACT, New Source Performance Standards for greenhouse gases, interstate transport, cooling towers, coal combustion residuals, and all the other new and pending regulations were added to the mix. As it is, the Obama administration has brought construction of new coal-fired generation to a near standstill, and things are only going to get harder as additional regulations take effect.

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Nor is EPA coordinating with the Federal Energy Regulatory Commission as well as other federal and state-level organizations responsible for the reliability of the grid. Needless to say, for EPA to be embarking on a regulatory agenda that threatens reliability without working closely with FERC is simply unacceptable.

I look forward to learning more from FERC's leadership about the reliability challenges we face, as well as the perspective of state-level officials responsible for keeping the lights on. I now yield to the ranking member, Mr. Rush for his opening statement.

Mr. WHITFIELD. At this time I would like to recognize the gentleman from Illinois.

Mr. RUSH. I want to yield, Mr. Chairman, to the ranking member.

Mr. WHITFIELD. OK. I will recognize the ranking member, Mr. Waxman of California, for his opening statement.

OPENING STATEMENT OF HON. HENRY A. WAXMAN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF CALIFORNIA

Mr. WAXMAN. Thank you, Mr. Chairman, and thank you, Mr. Rush, for the opportunity to make this opening statement.

This Republican House has been the most anti-environment in history. And today's hearing builds on that unfortunate record with yet another attack on EPA's efforts to reduce air pollution.

The rules under assault today will improve the health of millions of Americans. The first rule, the mercury and air toxics rule, will prevent up to 17,000 premature deaths each year. The benefits of this rule sharply exceed the costs by as much as 13 to one.

The second rule, EPA's cross-state air pollution rule, is also a tremendous victory for public health. Each year, this rule will prevent up to 34,000 premature deaths. In 2014, this rule will cost $800 million but will produce annual health benefits to Americans of between $120 billion and $280 billion. That is an outstanding return on investment for the American people.

Earlier this year, when Republicans wanted to block EPA's climate rules, they said they wanted to clean up other air pollution, just not greenhouse gases. Yesterday, when our committee voted to block air toxics rules for boilers and cement kilns, they said they care about air pollution but denied the health benefits from reducing air toxics such as mercury. Now, they are attacking the cross-state air pollution rule, which controls fine particulates. They ignore the severe effects of particulates on health documented in reams of peer-reviewed studies, and they claim that the rules will force so many coal plants to shut down that the reliability of our electric grid will be threatened.

Well, EPA examined this question and found that its rules will result in only a modest level of retirements, of older, dirtier, less efficient power plants, and that these retirements are not expected to have an adverse impact on the adequacy of electric generation. EPA's conclusions have been confirmed by several independent studies.

In August 2010, the Analysis Group concluded that "the electric industry is well positioned to comply with EPA's proposed air regulations without threatening electric system reliability." And they reaffirmed this finding in a June 2011 report.

The Bipartisan Policy Center's June 2011 analysis of the rules also found that "scenarios in which electric system reliability is broadly affected are unlikely to occur." In a December 2010 study, Charles River Associates found that "implementing EPA air regulations will not compromise electric system reliability."

The Congressional Research Service and others have also examined the issue. The stack of independent studies agrees on the key points. First, there is currently a substantial amount of excess generation capacity from natural gas plants built during the last decade. The Analysis Group found that the electric sector is expected to have over 100 gigawatts of surplus capacity in 2013. That is much more capacity than anyone has suggested might retire as a result of EPA's rules.

Second, the electric industry has a proven track record of rapidly installing large amounts of new capacity when it is needed. From 2000 to 2003, utilities added over 200 gigawatts of new capacity, and energy efficiency can often reduce the amount of needed generation even faster.

Third, the potential retirements are of old, small, inefficient, less-used coal plants that lack pollution controls. On average, these units are 55 years old. According to CRS, the main threat to these plants is cheap natural gas. Regardless of EPA's rules, these old plants are being replaced by more efficient natural gas plants.

Today, we will hear a lot about an informal assessment by FERC's staff that 81 gigawatts of generation are likely to close as a result of EPA's rules. Citing this assessment is a mistake, as we will hear today from FERC's chairman. This assessment was based on inaccurate assumptions and inadequate data, and it is out of date. It does not reflect the final EPA rules, as FERC has acknowledged.

The NERC and industry studies are also based on inaccurate assumptions of what EPA rules would require. The results are unreliable because they assumed standards far more burdensome than those EPA adopted.

The reliability of the electric grid is a serious topic, and it should not be used as an unfounded excuse to block important public health protections.

Thank you, Mr. Chairman.

Mr. WHITFIELD. Thank you.

At this time I recognize the gentleman from Texas, Mr. Olson, for his opening statement.

OPENING STATEMENT OF HON. PETE OLSON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Mr. OLSON. Thank you, Mr. Chairman. Thank you for your leadership in hosting the 12th hearing of the American Initiative.

When the Obama Administration's Environmental Protection Agency blindsided Texas by including in its cross-state pollution rule at the last minute, Texas utility companies warned that the decision would lead to a shortage of electricity, layoffs and higher energy prices. That was over 2 months ago. The EPA went full steam ahead with its rulemaking despite these concerns, and now we have learned that Luminant, the largest power generator in Texas, will close Texas lignite mines, idle two power plants and lay off 500 people. Luminant is one of the latest victims of an agency that is out of control. I hear it from my constituents, other Members of Congress and even President Obama himself when he withdrew a poorly drafted EPA ozone rule that was bad for the economy.

Today, we will hear from public utility commissioners and independent system operations. They are not here to make a political statement. They are here to tell us that there is no realistic way to even partially mitigate the substantial losses of available operating capacity that will result from this rule. Hopefully, members on both sides will heed their message and work together to find a more sensible solution.

I thank you, and yield to my colleague from Texas, the chairman emeritus, Mr. Barton.

OPENING STATEMENT OF HON. JOE BARTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Mr. BARTON. Thank you, Mr. Olson.

I want to welcome the FERC commissioners. I think it has been a while since we have had all five of you, so we are glad to have you.

It was interesting to me listening to Ranking Member Waxman. His assessment seems to be that we just overreact to all these EPA rules, that they are really not going to have much of an impact and we just need to hug each other and things will work out. Well, you folks are an independent agency, and EPA says all their rules might require 10-megawatt retirement. I think they say 10. You say 131. Well, that is quite a difference. Even if you split the difference, it is still approximately 70 megawatts. That is a lot of power. As my friend, Mr. Olson, just pointed out, this cross-state air transport rule that the EPA popped on us a month or so ago is going to cost a minimum of 500 jobs in my district, probably another 2,000 jobs that are directly impacted, and EPA's reaction to that was, the company that announced the layoffs yesterday just doesn't understand.

Well, my good friends at the FERC, today we want to hear your honest assessment, whatever it is, pro or con. This subcommittee wants the facts. You are all appointed by the President and your job is to give the best assessment as you can. We need to build a lot of power plants in this country in the next 10 years. It doesn't look like anybody is going to build a coal plant. It is almost impossible to permit a nuclear plant. That kind of leaves it to natural gas and perhaps wind power in certain areas of the country.

So Mr. Chairman, I will put my formal statement in the record, but I am delighted to have the FERC commissioners and the panelists that are going to follow them, and I look forward to an interesting hearing.

Mr. SHIMKUS. Would the gentleman from Texas who originally had the time, Mr. Olson——

Mr. BARTON. I yield to the gentleman from——

Mr. SHIMKUS. Would you yield?

Mr. BARTON. If I am allowed to.

OPENING STATEMENT OF HON. JOHN SHIMKUS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

Mr. SHIMKUS. Thank you. I also want to just welcome the commissioners, and having the EPA make a determination of the reliability of the generating capacity of this country and the transmission grid is like asking you to make an analysis of nitrous oxide emissions or asking you to make a Safe Drinking Water Act. We look forward to your analysis. I would let Chairman Waxman know that it is not only your own analysis, and I will have this up on the screen when we go to questions, but FERC is at 70 for moderate restriction, Bernstein and Associates 65 gigawatts. EPA is the lowest analysis of the loss of power than any either industry-selected or non-industry-selected evaluation of this. This is critical for the cost of energy and jobs in this country, and I agree with Mr. Barton that we really need your forthright and honest testimony the effect it is going to have on our consumers and jobs in this country.

Mr. WHITFIELD. The gentleman's time is expired. At this time I will recognize the gentleman from Illinois, Mr. Rush, for his 5-minute opening statement.

OPENING STATEMENT OF HON. BOBBY L. RUSH, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

Mr. RUSH. I want to thank you, Mr. Chairman, and I want to thank all the commissioners as well as your other expert witnesses for appearing before this subcommittee today.

Mr. Chairman, today we are holding a hearing to determine whether or not there is a need to further delay critical Clean Air Act rules including the Air Toxics Rule and the Cross-State Air Pollution Rule in order to address reliability issues.

Mr. Chairman, in my opinion, this is yet another all-out assault, attack on the EPA. It is, as I might borrow my friend from Illinois's phraseology, yet another Republican jihad, assault on the EPA. When will it end? I guess not until after the elections in November of 2012.

There has been much debate and widely divergent estimates over grid reliability issues stemming from the number of power plants that would need to be retired once these rules go into effect. As a matter of fact, some earlier reports speculated that a larger number of power plants up to 80 gigawatts or more may be retired as a result of EPA's regulations. However, Mr. Chairman, it must not go unsaid that these reports were based on the worst-case scenarios and the erroneous assumptions about what EPA might propose. More recent independent reports which look at what EPA actually proposed, including the Bipartisan Policy Center's entitled "Environmental Regulations and Electric System Reliability" only project 15 to 18 gigawatts of incremental coal plant retirements by 2015. This represents less than 6 percent of total coal-fired capacity and less than 2 percent of total generating capacity.

Additionally, many independent studies predict that these rules, including the Air Toxics Rule and the Cross-State Air Pollution Rule, will not threaten the economic health of the Nation but instead will in fact stimulate job growth while protecting the public health.

Under these new EPA air regulations, a small percentage of the oldest power plants will need to install pollution-control equipment to continue operations. The capital investments in pollution controls and new generation will create an estimated 1.46 million jobs or an average of 290,000 year-round jobs between 2010 and 2015. It is job stimulation in any way you want to look at it.

Due to abundant low-priced domestic natural gas supplies and reduced electricity demand, some electricity generators may elect to retire the old inefficient plants rather than invest capital to install pollution controls. This is not a bad thing; it is a good thing.

A new report from PJM Interconnection, the Nation's largest transmission operator, says since the reliability is not threatened by coal-fired power plant retirements spurred by new EPA rules despite the coal industry's claims that the impacts could be severe.

I have, Mr. Chairman, and I want to insert into the record a letter from Dynegy, a Houston-based coal-fired power company which supplies the Midwest Independent System Operator in Illinois and who is supportive of the EPA's rule.

Mr. WHITFIELD. Without objection.

[The information follows:]

Robert C. Flexon
President and Chief Executive Officer

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DYNEGY

September 12, 2011

Hon. Bobby Rush, Ranking Member
Energy and Power Subcommittee
Committee on Energy and Commerce
U.S. House of Representatives
2268 Rayburn House Office Building
Washington, D.C. 20515

Re: EPA's Cross-State Air Pollution Rule

Dear Congressman Rush:

We understand that the Energy and Power Subcommittee will be holding a hearing on Sept. 14 on EPA power-sector rules, including the Cross-State Air Pollution Rule (CSAPR), and reliability concerns. CSAPR, as you know, is a Clean Air Act rule focusing on interstate air emissions from electric generating units. We wanted to offer the following remarks for the record in order to make clear the position of Dynegy Inc on CSAPR. While we would note that the rule can be improved through technical corrections, we are supportive of the rule.

We fully understand the perception that the rule works some unfairness on certain business interests. However, we want you to know that this is not a uniformly-held position in the power sector; rather, it is a reflection of particular investment decisions. Having made different decisions (particularly with respect to our Illinois facilities), we have made substantial capital investments in state-of-the-art air pollution control devices. Any efforts to delay or derail CSAPR would undermine the reasonable, investment-backed expectations of Dynegy.

As an Illinois constituent, Dynegy provides wholesale power, capacity and ancillary services to utilities, cooperatives, municipalities and other energy companies in six states in our key U.S. regions of the Midwest, the Northeast and the West Coast. Dynegy's power generation portfolio consists of approximately 11,600 megawatts of baseload, intermediate and peaking power plants fueled by a mix of coal, fuel oil and natural gas. Our geographic, dispatch and fuel diversity contribute to a portfolio that is well-positioned to capitalize on regional differences in power prices and weather-driven demand to the benefit of consumers and businesses.

The orderly and predictable implementation of CSAPR actually removes business uncertainty in the electric power sector that was created when the federal courts invalidated the forerunner to CSAPR known as the Clean Air Interstate Rule. Like other capital-intensive industries, the power sector thrives and creates jobs in situations of certainty. In our case, CSAPR allows competitive markets to confer deserved economic returns on our investments in clean energy technology - investments made as a result of corporate policy, the operation of applicable law in the states in which we operate, and additional federal requirements. Dynegy's 3000 megawatts of generating assets in Illinois, enough to power roughly three million homes, are mostly coal-fired, base and intermediate-load facilities. These coal-fired operations employ about 700 individuals. Our capital investment in clean air technologies at these coal facilities totals about one billion dollars since EPA finalized CAIR in March 2005.

Your hearing addresses reliability. Our electric generation facilities in Illinois - facilities that do indeed burn coal but which have the most modern air emission controls - are an important part of the backbone of affordable and reliable power in the state. Reserve margins in the transport rule Midwest Group I states, where Dynegy coal-fired facilities are located, exceed target reserve levels. And EPA has adopted reasonable regulatory approaches under CSAPR, including allowing for both intrastate and interstate trading. For these reasons, Dynegy believes that delaying implementation of the CSAPR in Midwest/Group I states, is not necessary. Reliability concerns should be taken seriously. But the fact is that a responsible approach to implementation, the emergency authorities already available to energy regulators, and some prompt technical corrections to the rule, should be sufficient to resolve near-term concerns. Over the longer term, the sooner well-controlled facilities become the norm, the sooner we will resolve any tension between reliability and protection of human health and the environment.

Of course, it goes without saying that control of interstate air pollution serves important public policy objectives, including protection of human health and the environment as well as the preservation of opportunities for economic development in downwind communities.

Thank you for this opportunity to make our position known. The bottom line is that those corporations that have invested in effective air pollution control devices were counting on a stable regulatory environment. While no one suggests that CSAPR is perfect, its continued progress towards implementation is important for that stability.

Very truly yours,

Robert C Flexon

Robert C. Flexon

cc: Hon. Ed Whitfield, Chairman
Energy and Power Subcommittee
Committee on Energy and Commerce

lrw/2011-0912

Mr. RUSH. The Congressional Research Service found no evidence of the majority's predicted train wreck but instead found that the primary impacts that the EPA rules will be on the coal-fired power plants more than 40 years old that have not installed pollution controls. Many of these plants are inefficient and they should be replaced and they are being replaced regardless of EPA's rules.

Additionally, a Charles River Associates' report concluded that the electric system reliability can be maintained while improving public health through coal-to-gas conversion, new gas-fired generation, expansion of load management programs and established market and regulatory safeguards.

So Mr. Chairman, I join with you and the rest of the Republican jihadists. I am very eager to hear the testimony from the FERC commissioners as well as other witnesses here today over whether the EPA and other federal and State agencies have taken practical steps to plan for the implementation of these rules and have adopted approaches to ensure the electricity industry can comply without threatening electric system reliability.

Mr. Chairman, I thank you and I yield back the balance of my time, all of it.

Mr. WHITFIELD. At this time before we go to the testimony, I would like to recognize Mr. Gardner for the purpose of requesting putting into the record some documentation.

Mr. GARDNER. Thank you, Mr. Chairman. I would ask the letter from Tim Scott regarding this hearing be submitted for the record with unanimous consent.

Mr. WHITFIELD. Without objection. Thank you.

[The information follows:]

TIM SCOTT
1ST DISTRICT, SOUTH CAROLINA

ELECTED LEADERSHIP COMMITTEE

COMMITTEE ON RULES

COMMITTEE ON
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www.timscott.house.gov

September 14, 2011

Mr. Chairman,

This hearing on the impact of the Environmental Protection Agency's new and proposed power sector regulations on electric reliability could not come at a more critical time for my constituents in South Carolina. As the attached letter indicates, the South Carolina Public Service Commission ("SCPSC") has significant concerns with many of the pending regulations and has petitioned the Federal Energy Regulatory Commission ("FERC") to establish a joint board between the two agencies to study the impact EPA regulations will have on the reliability and affordability of electric power in the State of South Carolina.

It is critical that federal agencies work with the states to ensure transparency and reduce the amount of regulatory uncertainty facing our utility sector. Unnecessary increased costs of complying with many of these regulations will significantly impact job creation in my state, force electric customers to pay higher rates and could reduce generation capacity. These potential impacts, which are not insignificant, require collaboration at the state and federal level.

To the five of the FERC Commissioners testifying in front of your Committee today, I submit the following questions:

1. Have all the Commissioners received the letter from the South Carolina Public Service Commission dated September 1, 2011?

2. If so, has the Commission responded to South Carolina's request to establish a joint federal-state board to study the impact EPA regulations will have on the reliability and affordability of electric power in the State of South Carolina?

3. If the Commission has not responded to the request when does it anticipate a formal response back to South Carolina officials?

Sincerely,

Tim Scott
Member of Congress

The Public Service Commission
State of South Carolina

JOHN E. "BUTCH" HOWARD
COMMISSIONER, FIRST DISTRICT

P.O. DRAWER 11649
COLUMBIA, S.C. 29211
Phone: (803) 896-5220
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September 1, 2011

The Honorable Kimberly Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **Petition for Creation of a Joint Federal-State Board to Study Electric Reliability** Docket No. EL-__-000

Dear Secretary Bose:

Pursuant to Section 209(a) of the Federal Power Act (FPA) (16 U.S.C. § 824h(a)), the Public Service Commission of South Carolina (South Carolina PSC) and the South Carolina Office of Regulatory Staff (ORS)[1] petition for the establishment of a joint board[2] between the South Carolina PSC and the Federal Energy Regulatory Commission (FERC) to study the impact of regulations of the Environmental Protection Agency (EPA) on the reliability and affordability of electric power in the State of South Carolina. The South Carolina PSC further urges FERC to consider including interested public service commissions throughout the southeast to study the impact of the EPA regulations on the region and include other commissions and regions as may be requested. Additionally, the South Carolina PSC is making an information request to FERC pursuant to FPA Section 209(c) (16 U.S.C. § 824h(c)).

Our petition is motivated by concern that EPA is proceeding with a significant number of new power sector regulations that could lead to numerous retirements of

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[1] ORS is the South Carolina state agency charged with representing the public interest of South Carolina in utility regulation, including proceedings before the South Carolina PSC, pursuant to S.C. Code Ann. § 58-4-10 (Supp. 2010). Furthermore, by state statute, ORS is the designated entity to provide legal representation of the public interest before federal regulatory agencies and federal courts in proceedings that could affect the rates or service of any public utility. See S.C. Code Ann. § 58-4-50 (A)(8) (Supp. 2010). The public interest is clearly defined by statute at S.C. Code Ann. § 58-4-10 (Supp. 2010).

[2] S.C. Code Ann. § 58-27-170 (Supp. 2010) provides the South Carolina PSC and the ORS with the authority to hold joint hearings and make joint investigations, respectively, with any official board or commission of any state or of the United States.

electric generating units without adequately consulting with agencies and stakeholders with responsibility for the adequacy and affordability of electric service and without FERC and public service commissions fully understanding the cumulative impact of these EPA regulations. The potential effects of these EPA regulations on the quality, reliability and cost of electric service are of great concern. However, it does not appear that the nation's energy regulators—at either the national or state level—are fully cognizant of these impacts, and therefore they would have significant difficulty adequately planning for these effects. A joint board made up of nominees from the interested states and FERC representatives would allow us to cooperate and coordinate in exercising our mutual responsibilities in this area.

In addition, we ask that FERC request that EPA coordinate the promulgation of its regulations affecting the power sector with the joint board's work. The board's work will be of little use if EPA takes action and initiates compliance deadlines without considering the board's analysis and recommendations.

I. BACKGROUND

EPA has promulgated, proposed or is planning numerous regulations affecting the electric power sector. Recently, EPA finalized its Cross-State Air Pollution Rule (CSAPR), and it has proposed hazardous air pollutants standards for electric generators, coal ash regulations, and water intake structure regulations. It has put in place greenhouse gas permitting requirements for new and modified facilities, and it is about to propose greenhouse gas New Source Performance Standards for new, modified and existing facilities. EPA has also promulgated National Ambient Air Quality Standards (NAAQS) for sulfur dioxide and nitrogen dioxide, is about to promulgate NAAQS for ozone, and is about to propose NAAQS for fine particulate matter, all of which will affect the power sector.

EPA has not assessed the cumulative effect of all of these regulations on the reliability and affordability of electric power. In its hazardous air pollutants proposal, EPA said it had "already begun reaching out to key stakeholders," such as "groups with responsibility to assure an affordable and reliable supply of electricity including Public Utility Commissions (PUCs), Regional Transmission Organizations (RTOs), the National Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and DOE." 76 Fed. Reg. 24,976, 25,054 (May 3, 2011). However, the South Carolina PSC, at least, has not been contacted or consulted by EPA as to the impacts of its regulations on electric reliability in South Carolina.

Although it appears that there have been informal discussions between EPA and FERC staff, the impact of EPA's power sector regulations on electric reliability and affordability has not been comprehensively studied by FERC. Moreover, these discussions have not been made public, and stakeholders, including state public service commissions, have not been included in the discussions. In an August 1, 2011 letter in response to an inquiry from Senator Lisa Murkowski, FERC Chairman Wellinghoff and Commissioners Norris and LaFleur stated that FERC staff have done only an "informal assessment [that] offered only a preliminary look at how coal-fired units could be impacted by EPA rules, and [it] is inadequate to use as a basis for decision-making, given that it used information and assumptions that have changed."

As "informal" and "preliminary" as this analysis was, it nevertheless revealed that "40 GW of coal-fired generating capacity [is] 'likely' to retire, with another 41 GW 'very likely' to retire." This combined 81 GW that is "likely" or "very likely" to retire far exceeds any of EPA's projections and is significantly larger than forecasts made by financial institutions, consulting groups, and even industry groups. It is almost 8% of all installed capacity and 24% of the coal-fired fleet, the backbone of the nation's electric system. (Derived from Table 1.2, p.17, *Existing Capacity by Energy Source*, 2009, U.S. Energy Information Administration *Electric Power Annual 2009*, dated April 2011, http://www.eia.gov/cneaf/electricity/epa/epa_sum.html).

We are particularly concerned with very near-term compliance deadlines in the EPA rules, such as the 2012 and 2014 compliance deadlines in the just-promulgated CSAPR and the 2015 compliance deadline (with the possibility of a one-year extension) in the hazardous air pollutants rule. Chairman Wellinghoff's August 1, 2011, response, joined by Commissioners Norris and LaFleur, stated that, "In discussing whether there is enough time for new generation to come online *by 2018* to offset coal retirements, Commission staff identified several factors that can extend the project build horizon. These include the long lead time needed for some equipment, potential protests against pipeline siting and construction, transmission siting and construction issues, and environmental permitting. These factors slow the industry response in replacing retired units." Attachment to August 1, 2011 letter, *FERC Response to Senator Murkowski Proposed EPA Rules*, p. 3 (emphasis added). These are precisely the factors that concern us and should concern FERC in assessing whether EPA's compliance timelines, which are much earlier than 2018, are unrealistic.

We are not alone in raising concern about the adequacy of the analysis that has been undertaken to date of the impact of EPA's regulations on electric service reliability. Although South Carolina is not in the PJM region, the comments of PJM on the proposed hazardous air pollutants rule are instructive. According to PJM's August 4, 2011 comments, "[T]he analysis supporting the Proposed Rule has underestimated the risks to reliability of electric supply in light of the hard deadlines imposed pursuant to Clean Air Act § 112." Further, PJM's comments provide warning that "PJM's preliminary analysis . . . indicates that the number and size of retirements in EPA's analysis is significantly understated." PJM goes on to state that "the analysis does not address the potential for more localized transmission constraints . . . . The fact that potential retirements have been understated, combined with the fact PJM could have as little as 90 days notice of retirement under its current FERC-approved rules, renders EPA's conclusion that adequate resources will exist incomplete and erroneous."

Similarly, the August 4, 2011, comments of the Public Utility Commission of Texas on the hazardous air pollutants rule criticized EPA's reliability analysis as flawed. Noting the recent high temperatures in Texas, the comments stated that "[a]lthough ERCOT avoided the need for rolling outages because of its current electricity reserves, the ERCOT grid operated close to its capacity. It is clear that, had the EPA rules discussed in these comments been in effect, Texas would have experienced rolling outages and the risk of massive load curtailment."

And, Commissioner Moeller, in his separate response to Senator Murkowski's letter, stated that:

> The recent and enduring heat wave that simultaneously impacted a large portion of the population of the United States underscores the essential and life-saving importance of electric reliability. With economic weakness and closed factories throughout the nation, you might have expected the available power plants to easily handle the heat wave. Yet the operators of the power grid relied on all of their available resources, including coal plants that are expected to be shut down because of EPA decisions, in order to ensure the reliability of the grid and health and safety of the public.

II. PETITION FOR JOINT BOARD

In light of these concerns, and the possibility that the EPA rules may result in service by public utilities that is "inadequate or insufficient", the South Carolina PSC respectfully petitions this Commission pursuant to Section 209(a) of the Federal Power Act to establish a joint federal-state board to address the cumulative impact of enacted and pending EPA rules on electric reliability (hereinafter the "Joint Board on Reliability"). Pursuant to Section 385.1304 of the Commission's regulations, the South Carolina PSC is prepared to nominate representatives to the Joint Board on Reliability and urges the Commission to issue an order within thirty days establishing the Joint Board on Reliability and requesting nominations for members.

The Joint Board on Reliability should be given a specific focus and mission:

> *To study and define the cumulative impact on electric system reliability of current and pending EPA utility regulations on impacted states and regions, and to develop a set of recommendations for FERC, EPA, affected regional entities and state commissions to implement to ensure that the power sector rules do not impair reliability or result in unreasonable increases in electric rates, either on a state-by-state or region-by-region basis, or in the aggregate.*

We understand and agree that section 209 boards are "designed for use in unusual cases, and as a means of relief to the Commission when it might find itself unable to hear and determine cases before it, in the usual course, without undue delay." 18 CFR § 385.1304 (2011). It is difficult to imagine a more suitable candidate for formalized state-federal coordination than a threat to electric reliability arising from significant impending generation retirements. FERC has important responsibilities as to the reliability of the bulk power system. State regulatory commissions retain jurisdiction over resource adequacy and the reasonableness of electric service to ultimate consumers, which in many states is implemented through integrated resource planning. This shared responsibility for "keeping the lights on" in a reliable and affordable manner demands that we work together, in a formalized and meaningful forum, to study, influence and plan for the impact of EPA rules on electric reliability, and to recommend a course forward to deal with the rules' effects. Further, EPA's hazardous air pollutants Proposed Rule states that "Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC" to assure that electric reliability is maintained as new regulations are developed and implemented. 76 Fed. Reg. 24,976, 25,054 (May 3, 2011). A joint board is an effective "tool" to be pursued for maintaining reliability as contemplated by the EPA.

Moreover, as suggested in Chairman Wellinghoff's August 1, 2011, letter, joined by Commissioners Norris and LaFleur, it appears FERC may lack the necessary data to conduct this analysis "in the normal course without undue delay." 18 CFR § 385.1304 (2011). Working together, in coordination with electric utilities and other organizations (including NERC, the Regional Entities, and the Regional Transmission Organizations), we can gather the necessary data to conduct a meaningful analysis, quickly.

Assessing reliability impacts should not be deferred to regional transmission planning processes alone. Regional planning groups may be critical processes for *mitigating* reliability impacts, but they appear to be inadequate to study the impact of this set of EPA rules on all stakeholders in such a way that EPA can use the data to inform its decision-making process. A Joint Board on Reliability would be a more appropriate vehicle for accomplishing those goals.[3] Moreover, we believe that both FERC and state commissions and other state regulatory bodies must be involved in the process. FERC's expertise in the reliability of the bulk power system, and the resources of the FERC Office of Electric Reliability and state-level IRP resources must be brought to bear on this process.

III. REQUEST FOR INFORMATION

In addition to the request for the establishment of the Joint Board on Reliability, the South Carolina PSC respectfully requests that this Commission make available pursuant to FPA Section 209(c) (16 U.S.C. § 824h(c)) all information in the Commission's possession that will assist it, and the Joint Board on Reliability if established, in carrying out their tasks. Section 209(c) addresses the availability of

[3] This proposed approach is entirely consistent with resolutions of the National Association of Regulatory Utility Commissioners' (NARUC) Board of Directors, namely, February 16, 2011, *Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations*, and July 20, 2011, *Resolution on Increased Flexibility for the Implementation of EPA Rulemakings* (Resolutions attached).

information and reports to state commissions. It states that "[t]he Commission shall make available to the several State commissions such information and reports as may be of assistance in State regulation of public utilities." The issues raised in the South Carolina PSC's petition and in this information request directly relate to our responsibility to engage in "state regulation of public utilities."

Specifically, we request here any and all materials relating to the Commission's informal analysis of the reliability impact of the EPA rules and to staff's discussions with EPA. Information provided pursuant to this request should include, but not be limited to, any supporting materials that may have accompanied Chairman Wellinghoff's letter of August 1 to Senator Murkowski that have not yet been publicly released. We ask that all responsive information available pursuant to FPA Section 209(c) be provided directly to the South Carolina PSC within thirty days. This information should also be made available to the Joint Board on Reliability, if established.

Thank you for your prompt attention to this matter. It is of critical importance. We look forward to your action in response to this petition.

Sincerely,

John E. Howard

John E. "Butch" Howard, Chairman
Public Service Commission of SC

C. Dukes Scott, Executive Director
SC Office of Regulatory Staff

David A. Wright, Vice Chairman
Public Service Commission of SC

c: The Honorable Lindsey O. Graham, U. S. Senate
The Honorable James W. Demint, U. S. Senate
The Honorable Timothy E. Scott, U. S. House of Representatives
The Honorable Joe Wilson, U. S. House of Representatives
The Honorable Jeff D. Duncan, U. S. House of Representatives
The Honorable Harold W. "Trey" Gowdy, III, U.S. House of Representatives
The Honorable J. Michael "Mick" Mulvaney, U. S. House of Representatives
The Honorable James E. Clyburn, U. S. House of Representatives
The Honorable Nikki Randhawa Haley, Governor, State of South Carolina
The Honorable Alan McCrory Wilson, South Carolina Attorney General
The Honorable Thomas C. Alexander, South Carolina Senate
The Honorable C. Bradley Hutto, South Carolina Senate
The Honorable Luke A. Rankin, Sr., South Carolina Senate
The Honorable William E. Sandifer, III, South Carolina House of Representatives
The Honorable P. Michael Forrester, South Carolina House of Representatives
The Honorable Harry L. Ott, Jr., South Carolina House of Representatives

attachments

Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations[1]

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC) recognizes that the U.S. Environmental Protection Agency (EPA) is engaged in the development of public health and environmental regulations that will directly affect the electric power sector; *and*

WHEREAS, EPA is expected to promulgate regulations to be implemented by State environmental regulators concerning the interstate transport of sulfur dioxide and nitrogen oxides, cooling water intake, emissions of hazardous air pollutants and greenhouse gases, release of toxic and thermal pollution into waterways, and management of coal combustion solid waste; *and*

WHEREAS, NARUC at this time takes no position regarding the merits of these EPA rulemakings; *and*

WHEREAS, Such regulations under consideration by EPA could pose significant challenges for the electric power sector, with respect to the economic burden, the feasibility of implementation by the contemplated deadlines and the maintenance of system reliability; *and*

WHEREAS, EPA is expected to provide opportunities for public comment and input with respect to forthcoming regulations; *and*

WHEREAS, Compliance with forthcoming environmental regulations will affect consumers differently depending upon each State's electricity market and the nature of the decisions made by State regulators; *and*

WHEREAS, Addressing compliance with multiple regulatory requirements at the same time may help to reduce overall compliance costs and minimize risk assuming reasonable flexibility with respect to deadlines; *and*

WHEREAS, State utility regulators are well positioned to evaluate risks and benefits of various resource options through policies that appropriately account for and mitigate the risks arising from compliance with pending regulations; *and*

WHEREAS, Cooperation between utility commissions and environmental regulators can promote greater policy coordination and integration and improve the quality and effectiveness of electricity sector regulation; *and*

WHEREAS, State utility regulators, by working with the power sector and State and federal environmental regulators, can help to facilitate least-cost compliance with public health and environmental goals; *and*

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[1] Based upon Resolution on *Implications of Climate Policy for Ratepayers and Public Utilities*, adopted by NARUC Board of Directors on July 18, 2007.

WHEREAS, State utility regulators can help to minimize environmental risk as well as uncertainty regarding reliability and customer rate impacts by requesting regulated utilities with fossil generation to develop plans that evaluate all relevant environmental rulemakings at U.S. EPA; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2011 Winter Committee Meetings in Washington D.C., urges the EPA to ensure that, as it develops public health and environmental programs, it will:

- Avoid compromising energy system reliability;
- Seek ways to minimize cost impacts to consumers;
- Ensure that its actions do not impair the availability of adequate electricity and natural gas resources;
- Consider cumulative economic and reliability impacts in the process of developing multiple environmental rulemakings that impact the electricity sector;
- Recognize the needs of States and regions to deploy a diverse portfolio of cost-effective supply-side and demand-side resources based on the unique circumstances of each State and region;
- Encourage the development of innovative, multi-pollutant solutions to emissions challenges as well as collaborative research and development efforts in conjunction with the U.S. Department of Energy;
- Employ rigorous cost-benefit analyses consistent with federal law, in order to ensure sound public policy outcomes;
- Provide an appropriate degree of flexibility and timeframes for compliance that recognizes the highly localized and regional nature of the provision of electricity services in the U.S;
- Engage in timely and meaningful dialog with State energy regulators in pursuit of these objectives; *and*
- Recognize and account for, where possible, State or regional efforts already undertaken to address environmental challenges; *and be it further*

RESOLVED, That NARUC urges State utility regulators to actively engage with State and federal environmental regulators and to take other appropriate actions in furtherance of the goals of this resolution.

Sponsored by the Committees on Electricity and Energy Resources and the Environment
Adopted by the NARUC Board of Directors February 16, 2011

Resolution on Increased Flexibility for the Implementation of EPA Rulemakings

WHEREAS, The Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution on the *Role of State Regulatory Policies in the Development of Federal Environmental Regulations* on February 16, 2011; including the following statements:

- **WHEREAS,** NARUC at this time takes no position regarding the merits of these EPA rulemakings; *and*

- **WHEREAS,** Such regulations under consideration by EPA could pose significant challenges for the electric power sector and the State Regulatory Commissions with respect to the economic burden, the feasibility of implementation by the contemplated deadlines and the maintenance of system reliability; *and*

WHEREAS, NARUC wishes to continue to advance the policies set forth in the resolution as it relates to the proposed EPA rulemakings concerning the interstate transport of sulfur dioxide and nitrogen oxides, cooling water intake, emissions of hazardous air pollutants and greenhouse gases, release of toxic and thermal pollution into waterways, and management of coal combustion solids; *and*

WHEREAS, NARUC recognizes that a reliable energy supply is vital to support the nation's future economic growth, security, and quality of life; *and*

WHEREAS, There are many strategies available to States and utilities to comply with EPA regulations, including retrofits and installation of pollution control equipment, construction of new power plants and transmission upgrades to provide resource adequacy and system security where needed when power plants retire, purchases of power from wholesale markets, demand response, energy efficiency, and renewable energy policies – the collection of which can be implemented at different time frames by different interested parties and may constitute lower-cost options that provide benefits to ratepayers; *and*

WHEREAS, A retrofit timeline for multimillion dollar projects may take up to five-plus years, considering that the retrofit projects will need to be designed to address compliance with multiple regulatory requirements at the same time and requiring several steps that may include, but are not limited to: utility regulatory commission approval, front-end engineering, environmental permitting, detailed engineering, construction and startup; *and*

WHEREAS, Timelines may also be lengthened by the large number of multimillion dollar projects that will be in competition for the same skilled labor and resources; *and*

WHEREAS, NARUC recognizes that flexibility with the implementation of EPA regulations can lessen generation cost increases because of improved planning, selection of correct design for the resolution of multiple requirements, greater use of energy efficiency and demand-side resources, and orderly decision-making; *and*

WHEREAS, Some generators that will be impacted by the new EPA rulemakings are located in constrained areas or supply constrained areas and will need time to allow for transmission or new generation studies to resolve reliability issues; *and*

WHEREAS, The North American Electric Reliability Corporation (NERC) and regional RTOs will need time to study reliability issues associated with shutdown or repowering of generation; *and*

WHEREAS, NARUC recognizes that flexibility will allow time for these needed studies, *and*

WHEREAS, The Federal Energy Regulatory Commission (FERC), through its oversight of NERC, has authority over electric system reliability, and is in a position to require generators to provide sufficient notice to FERC, system operators, and State regulators of expected effects of forthcoming health and environmental regulations on operating plants to allow an opportunity for meaningful assessment and response to reliability claims; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2011 Summer Committee Meetings in Los Angeles, California, supports efforts to promote State and federal environmental and energy policies that will enhance the reliability of the nation's energy supply and minimize cost impacts to consumers by:

- Allowing utilities to coordinate the closure and/or retrofitting of existing electric generating units in an orderly manner that will ensure the continued supply of electricity and that will allow power generators to upgrade their facilities in the most cost effective way, while at the same time achieving attainable efficiency gains and environmental compliance; *and*

- Allowing regulatory options for units that are necessary for grid reliability that commit to retire or repower; *and*

- Allowing an EPA-directed phasing-in of the regulation requirements; *and*

- Establishing interim progress standards that ensure generation units meet EPA regulations in an orderly, cost-effective manner; *and be it further*

RESOLVED, That commissions should encourage utilities to plan for EPA regulations, and explore all options for complying with such regulations, in order to minimize costs to ratepayers; *and be it further*

RESOLVED, That FERC should work with the EPA to develop a process that requires generators to provide notice to FERC, system operators, and State regulators of expected effects of forthcoming EPA regulations on operating plants to allow an opportunity for meaningful assessment and response to reliability issues; *and be it further*

RESOLVED, That NARUC and its members should actively coordinate with their environmental regulatory counterparts, FERC, and the electric power sector ensuring electric system reliability and encourage the use of all available tools that provide flexibility in EPA regulation requirements reflecting the timeline and cost efficiency concerns embodied in this resolution to ensure continuing emission reduction progress while minimizing capital costs, rate increases and other economic impacts while meeting public health and environmental goals.

Sponsored by the Subcommittee on Clean Coal and Carbon Sequestration and the Committees on Electricity and Energy Resources and the Environment
Adopted by the NARUC Board of Directors July 20, 2011

Mr. WHITFIELD. At this time I also want to welcome the FERC commissioners. We appreciate very much your taking time to be here. We are sorry for the delay this morning.

We have with us today the Chairman of the Federal Energy Regulatory Commission, the Honorable Jon Wellinghoff. Also, Commissioner Phillip Moeller, Marc Spitzer, John Norris and Cheryl LaFleur, and at this time, Chairman Wellinghoff, we will recognize you for your 5-minute opening statement and then we will just go down the line.

STATEMENTS OF JON WELLINGHOFF, CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION; PHILIP D. MOELLER, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION; MARC SPITZER, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION; JOHN R. NORRIS, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION; AND CHERYL A. LAFLEUR, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION

STATEMENT OF JON WELLINGHOFF

Mr. WELLINGHOFF. Thank you, Mr. Chairman and members of the committee. I appreciate the opportunity to be here and testify before you today.

Electric reliability and environmental protection are both important to this country's future. The issues are related as, for example, regulations that the EPA recently finalized or is considering will affect the operation of some electric-generating units.

With sufficient information and time, the electric industry can plan to meet both its reliability and environmental obligations. Most notably, existing planning authorities with developed modeling capabilities have or could obtain all the necessary data and tools to analyze the potential local and regional reliability impacts stemming from the EPA regulations. These planning authorities provide the appropriate forums for addressing this issue. Some are already taking steps to account for implementation of these EPA regulations. For planning authorities to conduct these analyses, they need early notice of retirements to accurately identify and address reliability issues.

The Commission also has a role to play with respect to electric reliability. In general, the Commission has used its existing authority in the past to protect reliability. To this end, the Commission has overseen the establishment of mandatory and enforceable standards that protect the reliability of the bulk power system. Looking forward, the Commission does and will, for example, review studies to determine the changes that occur due to changes in mix and location of resources in a region as well as planning-related proposals that account for implementation of these EPA regulations.

The Commission also can and will share our staff's expertise with the EPA when appropriate. Commission staff has had numerous consultations with EPA staff on issues related to these EPA regulations including informal assessments that each has conducted. Commissioner staff's informal assessments of generator retirements are inadequate to be used as a basis for decision making.

More generally, it is important to recognize that although the Commission is well suited and able to perform its statutory duties including those with respect to reliability, it does not possess the data nor the models necessary to replace the industry's individual and collective planning processes in addressing the potential local and regional impacts of these EPA regulations on electric reliability.

That completes my summary of my testimony. Thank you, Mr. Chairman.

[The prepared statement of Mr. Wellinghoff follows:]

One Page Summary of Testimony of Chairman Jon Wellinghoff
Federal Energy Regulatory Commission
Before the House Subcommittee on Energy and Power
Of the Committee on Energy and Commerce
United States House of Representatives
September 14, 2011

Electric reliability and environmental protection are both important to this country's future. The issues are related as, for example, regulations that the EPA recently finalized or is considering will affect the operation of some electric generation units. With sufficient information and time, the electric industry can plan to meet both its reliability and environmental obligations.

Most notably, existing planning authorities with developed modeling capabilities have or could obtain all the necessary data and tools to analyze the potential local and regional reliability impacts stemming from the EPA regulations. These planning authorities provide the appropriate forums for addressing this issue. Some are already taking steps to account for implementation of these EPA regulations. For planning authorities to conduct these analyses, they will need early notice of retirements to accurately identify and address reliability issues.

The Commission also has a role to play with respect to electric reliability. In general, the Commission has used its existing authority in the past to protect reliability. To this end, the Commission has overseen the establishment of mandatory and enforceable standards that protect the reliability of the Bulk-Power System. Looking forward, the Commission does and will, for example, review studies to determine the changes that occur due to changes in the mix and location of resources in a region, as well as planning-related proposals that account for implementation of these EPA regulations. The Commission also can and will share our staff's expertise with EPA when appropriate. Commission staff has had numerous consultations with EPA staff on issues related to these EPA regulations, including informal assessments that each has conducted.

Commission staff's informal assessment of generator retirements is inadequate to use as a basis for decision making. More generally, it is important to recognize that, although the Commission is well-suited and able to perform its statutory duties, including those with respect to reliability, it does not possess either the data or the models necessary to replace the industry's individual and collective planning processes in addressing the potential local and regional impacts of these EPA regulations on electric reliability.

Testimony of Chairman Jon Wellinghoff

Federal Energy Regulatory Commission

Before the House Subcommittee on Energy and Power

Of the Committee on Energy and Commerce

United States House of Representatives

September 14, 2011

Mr. Chairman, Ranking Member Rush, and members of the Subcommittee:

My name is Jon Wellinghoff, and I am the Chairman of the Federal Energy Regulatory Commission (FERC or Commission). With me are Commissioners Marc Spitzer, Phil Moeller, John Norris, and Cheryl LaFleur. I thank you for the opportunity to appear before you today to discuss our views on the planning processes used in this country by utilities and regional planning authorities to maintain a reliable electric grid and potential impacts of the Environmental Protection Agency's (EPA) new and proposed power sector regulations on electric reliability and those planning processes.

Electric reliability and environmental protection are both important to this country's future. The issues are related. For example, regulations that the EPA recently finalized or is now considering will affect the operation of some electric generation units. With sufficient information and time, the electric industry can plan to meet both its reliability and environmental obligations.

Most notably, existing planning authorities with developed modeling capabilities have or could obtain all the necessary data and tools to analyze the potential local and regional reliability impacts stemming from those EPA regulations. Indeed, planning authorities such as the PJM Regional Transmission Organization are already taking steps in that direction. Given these capabilities, these planning authorities provide the appropriate forums for addressing any potential local and regional impacts of these EPA regulations on electric reliability. However, for planning authorities to conduct these analyses, they will need early notice of retirements to accurately identify and address reliability issues.

The Commission also has a role to play with respect to electric reliability. In general, the Commission has used its existing authority in the past to protect reliability. To this end, the Commission has overseen the establishment of mandatory and enforceable standards that protect the reliability of the Bulk-Power System. Looking forward, the Commission does and will, for example, review studies to determine the changes that occur due to changes in the mix and location of resources in a region, as well as planning-related proposals that account for implementation of these EPA regulations. The Commission also can and will share our staff's expertise with EPA when appropriate. Commission staff has had numerous consultations with EPA staff on issues related to these EPA regulations, including informal assessments that each has conducted.

I will discuss more fully below staff's informal assessment of generator retirements and the reasons why it is inadequate to use as a basis for decision making. More generally, however, it is important to recognize that, although the Commission is well-suited and able to perform its statutory duties, including those with respect to reliability, it does not possess either the data or the models necessary to replace the industry's individual and collective planning processes in addressing the potential local and regional impacts of the EPA regulations on electric reliability.

Industry Can Plan to Meet its Reliability and Environmental Obligations

As I have said before, available data indicates that the electric industry has added significant amounts of generating capacity when circumstances warranted. As a point of reference, EIA data shows that between 2000 and 2004, an annual average of 38.74 GW of capacity was added nationally, with a peak addition of 58.06 GW in 2002. Similarly, the electric industry has the ability to plan for the EPA regulations, which will affect the operation of some electric generation units. In particular, existing planning authorities with developed modeling capabilities can analyze the potential local and regional reliability impacts stemming from these results.

A number of factors would need to be taken into consideration in such an analysis. One such factor is generator retirements. Some information related to generator retirements is largely publicly available. This information includes information such as which plants currently have SO_2 controls, the age of each generating plant, and whether the plant owner had already announced plans to retire the plant.

Much other information related to generator retirement is not publicly available. For example, detailed financial information regarding a generator unit owner's current status, access to capital, and the current market and contract positions of the facility would influence the generator's likely business plan. Additionally, the extent of an entity's financial commitments to affected units, the percentage of the entity's fleet that is impacted, and any other large scale projects or issues could affect decisions to retire or retrofit any given unit.

Further, detailed physical information would be needed to perform an adequate determination about whether a specific generator is likely to retire or not. Documents such as site maps or facility diagrams would be necessary to determine the size of the site on which the generation is located, the ability of the site to accommodate new or additional equipment, site specific impediments to required equipment or construction, and the estimated cost of needed retrofits. Outage information, including the impact to the unit's availability or likelihood of equipment malfunction, also would be needed to perform an adequate assessment. Thus, generator retirements are business decisions that are based in large part on non-public, proprietary information and models that the Commission does not possess. Utilities have been hesitant to provide this type of proprietary information to FERC because of concerns that FERC could not prevent its further release under the Freedom of Information Act.

Analyzing the potential for generator retirement alone cannot provide a sufficient basis for an assessment of the local and regional reliability impacts of the proposed EPA regulations. The analysis would also need to evaluate whether the generator's retirement would cause a reliability concern. Any assessment would need to analyze detailed reliability information and study such information as the generator unit's necessity to the connecting network to meet all reliability standards. Such an analysis must include all anticipated conditions considering such items as alternative network configurations and maintenance outage schedules of other elements in the Bulk-Power System network. To perform these types of analyses, generator specific retirement or retrofit information would need to be available as well as all of the limiting criteria of the reconfigured system.

In addition, if the analysis showed that the retirement might cause a reliability concern, a reliability assessment would need to evaluate whether there are alternatives that might be available to offset any generator retirement; for example, whether a retiring generating unit could be retrofitted with a gas burner or a new generator could replace the retiring generator. The assessment would also need to evaluate whether demand response or energy efficiency could replace the capacity lost by retiring generation. There could also be new or planned generation or transmission that could mitigate a reliability standards violation.

Existing planning authorities have developed modeling capabilities to analyze the potential local and regional reliability impacts of the proposed EPA regulations. They now have or could obtain all the necessary data to perform this analysis. These processes use specific entity and regional information such as the many different configurations of the network, the flexibility and profile of the load pockets, the limiting reliability criteria of the affected systems, local and regional plans to alleviate constraints, and the deliverability of alternative resources. By contrast, this information is not typically needed when the Commission reviews and enforces reliability standards under Section 215 of the Federal Power Act.

For these reasons, the existing planning authorities provide the appropriate forums for addressing any potential impact of these EPA regulations on electric reliability. As I noted earlier, for planning authorities to conduct these analyses, they will need early notice of retirements to accurately identify and address reliability issues.

The Commission's Role in Protecting Reliability

The Commission also has a role to play with respect to electric reliability. Under Section 215 of the Federal Power Act, the Commission's role and responsibilities in ensuring the Bulk-Power System operates reliably is to establish and enforce electric Reliability Standards developed by the Electric Reliability Organization (ERO), which is the North American Electric Reliability Corporation (NERC). By law, Reliability Standards cannot include any requirement to enlarge Bulk-Power System facilities or to construct new transmission capacity or generation capacity. 16 U.S.C. § 824o(a)(3) (2006). Further, section 215(i) of the FPA states that section 215 "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."

In addition, the Commission has taken action pursuant to its ratemaking authority to require or allow utilities to operate when needed while meeting their environmental obligations.

Looking forward, the Commission does and will review studies to determine the changes that occur due to a change in the mix and location of resources in a region. The Commission also does and will review planning-related proposals that account for implementation of these proposed EPA regulations. The Commission also can and will share our staff's expertise with EPA when appropriate.

The ability to fulfill these statutory responsibilities, however, does not mean that the Commission is equipped or staffed to perform a comprehensive resource analysis and plan that would assess and address the potential local and regional electric reliability impacts of the proposed EPA regulations. I do not believe that developing such capability at the Commission is an efficient use of government resources when, as discussed above, the electric industry through existing planning authorities can conduct such analysis. I also note that FERC does not have the authority to require the construction or retirement of generation facilities.

Commission Staff Informal Assessment

As noted above, Commission staff conducted an informal assessment of generator retirements. That informal assessment must be viewed in light of the factors that would need to be considered to perform an adequate assessment of the potential local and regional reliability impacts of these EPA regulations. Although staff provided an adequate back-of-the envelope first assessment of the amount and location of potential generator retirements, that informal assessment cannot be relied upon to determine specific effects on system reliability. Therefore, it is inadequate to use as a basis for decision making.

Commission staff's informal assessment was based on information that was publicly available at the time it was conducted. For example, some generators had already announced that they would be retiring regardless of the outcome of the EPA regulations. However, as outlined above, much of the information necessary to perform an accurate assessment of generator retirements is not public.

Staff also had to make numerous assumptions in performing its informal assessment. First, staff's informal assessment was performed before all the regulations were proposed and finalized. Therefore, staff had to make assumptions regarding what the proposed EPA regulations might require. These rules have since changed during the EPA rulemaking process and may continue to change. For example, similar to other national studies performed at the time, staff's informal assessment assumed that the steam generating units employing once-through cooling systems could be required to replace their cooling water systems with closed-loop cooling systems. However, EPA states that under its proposed rules, closed-loop cooling systems are not required of existing facilities and that "in meeting the impingement requirement that a limited number of fish be killed by a facility, the facility would determine which technology to employ to meet the impingement limit."

Second, staff had to make assumptions in evaluating the susceptibility of individual generators to the proposed EPA regulations. In performing the informal assessment, Commission staff chose certain factors to consider, such as what generators had SO_2 controls, age of the plant, and whether the plant owner had already announced plans to retire the plant. Commission staff then decided to weight each factor. As these inputs to the informal assessment have changed, projected outcomes would necessarily change.

Depending on the scenario that was evaluated, that informal, preliminary assessment produced varying results, ranging from 40 GW to 81 GW in estimated retirements. It is true that the first iteration of the results showed 81 GW as likely or very likely to retire. However, as time passed and Commission staff gained more knowledge about what EPA was proposing and included actual announced plant retirements, those numbers decreased.

Finally, staff's preliminary assessment only evaluated potential generator retirements, it did not evaluate the potential local or regional reliability impacts those retirements might have. It also did not evaluate any alternatives that might be available to the regions to offset any generator loss such as new or planned generation or transmission, retrofits of coal-to-gas burners, demand-side resources, or energy efficiency strategies.

Conclusion

In conclusion, I believe that given enough information and time, the electric industry can plan to meet whatever EPA regulations become final. While the Commission has an important role to play in protecting electric reliability, it does not have the data and models necessary to replace the industry's individual and collective planning processes. Industry, using existing planning authorities that have already developed modeling capabilities, have or could get all the necessary data for such analysis. These planning authorities are already taking steps to account for implementation of these EPA regulations. Therefore, these planning authorities provide the appropriate forums for addressing any potential impact of the proposed EPA regulations.

Mr. WHITFIELD. Thank you.

Mr. Moeller, you are recognized for 5 minutes.

STATEMENT OF PHILIP D. MOELLER

Mr. MOELLER. Thank you, Mr. Chairman and Ranking Member Rush, members of the committee. It is a pleasure to be here today. Thank you for inviting us to testify and your interest in this matter because it is of great importance to the Nation.

At FERC, our statutory interest in this is primarily having to with bulk system electric reliability as that is the responsibility that you gave us in 2005 under Section 215 of the Federal Power Act but we also have an interest in policies that can affect rates because of our statutory direction there as well.

I believe this Nation can retire a significant amount of existing generation. In fact, nearly all of our existing generation will be retired and replaced within the next 40 years. The key questions are which plants are going to be retired, where are they and what is a manageable time frame in which to retire them.

In retiring a significant amount of existing generation within a short period of time, though, does have cost impacts and so while there will be health benefits to closing certain plants, there are also consequences to rising electricity rates.

Now, one common assumption is that many of these coal-fired plants, especially the baseload ones, will be replaced with new generation fueled by natural gas. But that assumption is based on the fact that we have new domestic supplies of natural gas, largely from shale deposits, that have been keeping prices in a moderate level, that appear to be a moderate level going out in the futures markets. But if there are legislative or regulatory efforts to restrict this new supply of gas, the price of shutting these coal plants will rise significantly, and in addition, the Nation's natural gas pipeline network will need to be expanded to meet this increased demand to keep prices reasonable. At a minimum, this will take a few years.

Now, the suite of proposed EPA rules and the timelines associated with each of these proposed rules impact different regions in different ways, and this adds to the complexity of developing solutions. Although some regions do have excess generating capacity and can absorb retirement, the laws of physics dictate that analyzing the impact must be done on a granular level down to the specific load pockets that are affected. In my letter to Senator Murkowski that I attached to my testimony, I provide a case study of the successful retirement of four plants in the Philadelphia area, but there were challenges and costs associated with those retirements.

Now, I have called for FERC to be more involved in analyzing the EPA rules from a reliability standpoint and a more open process for public input. Given the dynamic nature of the rulemaking process, we can't expect to have a perfect analysis of the impacts but we can make our best effort involving EPA, DOE, NERC, regions. The State utility commissions would be essential.

In addition, there have been some other ideas and some other measures that have been suggested to minimize the disruption to the electric sector. Clarifying the conflict between the Clean Air Act and the Federal Power Act when reliability is at stake is one idea. Determining each agency's statutory authorities for reliability conditions is another, and requiring more advance notice of plant retirements could be helpful.

Again, I appreciate the chance to testify before you, your interest in this issue, and I look forward to answering any questions you may have.

[The prepared statement of Mr. Moeller follows:]

Summary of the Testimony of Commissioner Philip D. Moeller
Before the U.S. House of Representatives
Committee on Energy and Commerce,
Subcommittee on Energy and Power

September 14, 2011

Two sets of consequences arise from the implementation of the EPA rules. One is economic and the other is reliability. On the economic front, the law of supply and demand means that removing any significant amount of generation from the nation's supply of generators will almost surely have price-raising consequences for electric consumers. This can benefit some generation owners and be detrimental to others.

With respect to reliability, I remain concerned that the timeline for electric utility planning and implementation is not compatible with the EPA timelines for its new regulations. Yet efforts to analyze the reliability and economic consequences of the EPA rules do not have to perfectly predict every consequence of such rules. Yet someone should convene the proper decision makers to begin a serious analysis of the rules. Perhaps such a process would include EPA, FERC, US DOE, NERC, and regional electric planners.

Since FERC does not generally outsource its reliability obligations to NERC or the RTOs and ISOs, I do not believe that we should outsource the reliability questions related to EPA regulations to NERC or the RTOs and ISOs.

Testimony of Commissioner Philip D. Moeller

Before the U.S. House of Representatives
Committee on Energy and Commerce,
Subcommittee on Energy and Power

Regarding the Impact of Regulations Proposed by the
Environmental Protection Agency (EPA)

September 14, 2011

Chairman Whitfield, Ranking Member Rush, and members of the Subcommittee, thank you for the invitation to testify on the subject of how regulations by the Environmental Protection Agency are expected to impact the reliability of electricity in this nation. As the people in San Diego and surrounding areas experienced last week, modern society cannot function in any useful way without a continuous and reliable supply of electricity.

As today's hearing will likely demonstrate, EPA is considering a suite of rules that will—if implemented—affect the nation's electric generation fleet. These rules all have different implementation timelines and the ability of regulated entities to comply will differ as well. This has created a high degree of uncertainty in the electric generation sector as to whether specific units should be retired or retrofitted, and if so, when these decisions should be made. Despite this uncertainty, this nation can retire a significant amount of older, fossil-based generation. However, such retirements need to be handled in an orderly way to avoid regulatory, economic, and reliability chaos.

As a Commissioner, I can be "fuel neutral" when it comes to assuring that our nation's wholesale electric rates are just and reasonable. But I cannot be neutral on the subject of reliability. As the recent heat waves this summer showed, generation units that rarely run were essential to providing reliable electric service when the health, safety and economic livelihood of citizens was at stake.

Two sets of consequences arise from the implementation of the EPA rules. One is economic and the other is reliability. Although different, they are related. On the economic front, the law of supply and demand means that removing any significant amount of generation from the nation's supply of generators will almost surely have price-raising consequences for electric consumers. This can benefit some generation owners and be detrimental to others. And it is not FERC's role to determine whether the public health benefits of closing certain units outweigh the public health consequences of higher electricity prices. But the fact that higher prices can impact public health and safety needs to be acknowledged.

Given the common underlying assumption that power plants fueled by natural gas can be built to replace retiring coal plants, the future availability of natural gas is critical to understanding the economic costs of new EPA regulations. Yet at this time, I am not aware that the EPA has clearly indicated that new sources of natural gas, such as fracking, will be available to help supply new needs for gas. Additionally, a lack of necessary pipeline capacity creates challenges to the extent that pipelines will need to be built or upgraded to provide adequate fuel.

With respect to reliability, I remain concerned that the timeline for electric utility planning and implementation is not compatible with the EPA timelines for its new regulations. Constructing needed transmission assets in this nation is still a very challenging endeavor. Planning, cost-allocation, permitting, siting, and construction are often extremely difficult and controversial, often leading to years of litigation, delay and potentially stranded capital.

Although several public reports indicate that certain regions of this nation should have adequate capacity even after a certain amount of coal plants are retired, the laws of physics dictate that changing the generation mix has implications that are very specific to the location of customers ("load") and the generating plants that remain.[1] Smaller plants may not be needed so much for the amount of energy they provide but rather for the voltage support they provide at that specific location, especially during times of high demand (such as summer and winter peaks, when an adequate supply of electricity is critical to health and safety). Substituting other generation in a different location may not replace the benefits that a plant in that location delivers.

For this reason, the debate over the amount of coal generation that should be retired may miss the larger point. Except for most hydroelectric facilities, our existing electric generation is very likely to be retired in this country within 40

[1] For an example of the impact on reliability from the retirement of specific coal plants, see my attached letter of August 1, 2011 to Senator Murkowski on the retirement of the Eddystone and Cromby coal units, at page 9.

years, to be gradually replaced with newer generating plants. As I have emphasized, instead of concentrating on how many coal plants to retire, the focus should be on the timing of when specific units are likely to retire and what needs to be done to allow them to retire with the least disruption to the nation.

Such an effort to analyze the reliability and economic consequences of the EPA rules does not have to perfectly predict every consequence of such rules. Yet I feel that someone should convene the proper decision makers to begin a serious analysis of the rules. Perhaps such a process would include EPA, FERC, the Department of Energy, NERC, and regional electric planners. Rules requiring advance notice of plant shutdowns could be modified. Clarification of existing legal authority to address reliability challenges by all the affected entities seems helpful. Legislation clarifying the role of EPA and FERC in the event of a conflict over air policy and electric reliability could also be helpful.

At FERC, we hold hearings, conferences, and meetings that are open to the public on our various statutory obligations, and by my count, the Commission has held at least four public meetings on electric reliability within the past two years. In my opinion, FERC and its staff are committed to ensuring that the power grid improves its reliability, so that blackouts like the event last week in San Diego are less likely to happen again.

When it comes to reliability, we do not outsource that function to private entities known as RTOs or ISOs,[2] as those entities do not have the statutory authority of this Commission to ensure reliability. Nor do we generally outsource our reliability obligations to the North American Electric Reliability Corporation (NERC), as that would be inconsistent with the law. According to the law, FERC is obligated to review and approve the reliability standards of NERC, and to consider, on its own motion or upon complaint, a proposed reliability standard to address a specific matter.

Since we do not outsource our reliability obligations to the RTOs and ISOs, I do not believe that we should outsource the reliability questions related to EPA regulations to the RTOs and ISOs. Such a delegation of our expertise would be unprecedented, especially in light of the impacts that some, including FERC staff, expect from the EPA regulations. Nor do I believe that a private entity like NERC is the only organization capable of examining the vital issue of reliability. While NERC has experts from industry that can examine reliability issues, FERC is part of the federal government, and FERC has a statutory obligation to consider matters that could have an impact on the reliability standards.[3]

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[2] RTOs are Regional Transmission Organizations and ISOs are Independent System Operators organized under rules and policies established by FERC under its orders known as Order No. 888 and Order No. 2000.

[3] As stated under Section 215 of the Federal Power Act, the "Commission, upon its own motion or upon complaint, may order the Electric Reliability Organization [certified to be NERC] to submit to the Commission a proposed reliability standard or a modification to a reliability standard that addresses a

While I agree that it would be impossible to know what all the final EPA rules will eventually require, and while I agree that it would be impossible to know with certainty which coal plants will shut down as a result of EPA regulations, I see a need for FERC to become further involved in the reliability implications of EPA actions. Specifically, I have said that "the federal government needs to convene an open and transparent process to assess the reliability implications of the EPA rules individually and in aggregate."[4] I have also said, "at minimum, the Commission should direct its staff to use its expertise to perform an analysis of the EPA's rules that could impact reliability of electricity —and disclose that analysis for public comment—and then hold a technical conference for public input."[5]

The electric industry can plan to meet whatever EPA regulations become final. This nation has complied with EPA regulations in the past, and we can do it in the future, given enough time and information. Yet, that is the basic question that we face today: how much time and information will be needed by the public so that EPA regulations can be followed?

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specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section." If retiring one or two coal plants could impact the ability of grid operators to comply with NERC standards, the simultaneous retirement of many coal plants nationwide would similarly be expected to impact NERC standards.

[4] See pages 10-11 of my letter to Senator Murkowski for my recommendations.

[5] Ibid.

Given that many EPA regulations impacting the power grid are not yet final, I recognize that FERC cannot arrive at a perfect and complete understanding of how EPA proposals will impact reliability. But FERC continuously faces uncertainty about future conditions for the energy industry, and despite uncertainty, FERC acts using its best judgment and in consideration of the best available information. For example, this nation faces uncertainty about the threat facing the future power grid from future threats to cyber security. Yet we act to avoid these threats today, despite not knowing what technology will be used in the future power grid, and despite not knowing when or if any particular cyber attack will come. In other words, not being absolutely certain of the future has never been a good argument in favor of stopping discussion about problems that could arise in the future.

I have recommended an open process involving FERC, NERC and stakeholders to help reduce the possibility that we will have reliability problems as a result of the EPA—I do not expect that we could undertake a process that will result in a perfect understanding of which coal plants will retire.

Thank you again for the opportunity to testify. I look forward to working with you in the future and to answering any questions.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

Office of Commissioner Philip D. Moeller

August 1, 2011

The Honorable Lisa A. Murkowski
United States Senate
Washington, DC 20510

Dear Senator Murkowski:

Thank you for your continuing interest in our work at the Federal Energy Regulatory Commission (FERC). As described in your letter to me, I raised the issue of how actions of the Environmental Protection Agency (EPA) could impact the reliability of our nation's electric system at the Commission's September 2010 open meeting, and I have been deeply interested in how our staff has been communicating with both the public and within government on this issue of critical importance to our nation. Thus, I share your concern about ensuring that we maintain a reliable and affordable supply of electricity.

Given these concerns, I have long-stated that I can be "fuel neutral" but I cannot be "reliability neutral". That is, I can be neutral as a regulator with regard to how competitive markets ultimately decide which types of power plants are most efficient and affordable, regardless of whether those power plants are fueled by water, natural gas, fuel oil, uranium, coal, wind, the sun, or any other fuel. But I cannot be neutral about the reliability of our electricity.

The Federal Power Act provides this Commission with statutory responsibilities over certain reliability matters. For that reason, the Commission has engineering staff in its Office of Electric Reliability that is dedicated to the topic of electric reliability, and many other Offices at the Commission have engineering and technical staff with expertise on that topic. Thus, I believe that this Commission can play an important role in providing information to the EPA on the extent to which its proposed rules will have an impact on electric reliability.

Given that you've sent similar letters to my fellow Commissioners, my answers could differ from their responses. Yet I think that should be expected, as we are individuals with potentially different views on this matter.

Thank you for asking these questions. Here are my answers:

Question 1. *With respect to the impact on electric reliability of the listed EPA rules affecting generation of electric power, please list and describe the Commission's actions taken; studies conducted; assistance provided to any other agency, including EPA; collaborative efforts with any other agency; and provision of data to any other agency.*

Answer: Concerning the impact of the listed EPA rules on electric reliability, the Commission has not acted or studied or provided assistance to any agency, including EPA. Because this answer may not be expected, I wish to clarify that the Commission acts mostly through orders in individual proceedings, although it sometimes issues reports, or holds conferences for the public, or acts in other ways.

While the Commission itself may not have acted, individual Commissioners can express their opinions, as can the staff of the Commission. I have been informed that our staff has provided assistance to other federal agencies on this topic, and that the staff has been studying various impacts of EPA proposals on energy markets. Such assistance by staff is not binding upon the Commission, and can take place without the knowledge of all or some Commissioners. The relationship of the Commission to its staff is described in the Code of Federal Regulations, and includes the following:

> The Commission staff provides informal advice and assistance to the general public and to prospective applicants for licenses, certificates, and other Commission authorizations. Opinions expressed by the staff do not represent the official views of the Commission, but are designed to aid the public and facilitate the accomplishment of the Commission's functions. Inquiries may be directed to the chief of the appropriate office or division. 18 CFR Section 388.104(a).

In addition, the Commission has "delegated authority" to several individuals on its staff. That delegated authority often extends only to matters that are unopposed or of a noncontroversial nature.[1]

[1] *See* 18 CFR Section 375.301(c); 18 CFR Section 375.303(b); 18 CFR Section 375.307(b); 18 CFR Section 375.308(x); 18 CFR Section 375.315(b). And for a general discussion of staff's relationship to Commission action, *see*, *Obtaining Guidance on Regulatory Requirements,* 123 FERC ¶ 61,157, at PP 30-34 (2008).

Question 2. *Regarding collaborative efforts between FERC and EPA described above, has an Inter-Agency Task Force been established? If so, please state or provide:*

- a. *the date it was established;*
- b. *the source of its authority;*
- c. *a copy of its charter;*
- d. *a description of the scope of its work;*
- e. *a schedule of its meetings, including a list of its meetings to date and any planned meetings;*
- f. *any minutes of its meetings; and*
- g. *a list of the agencies and agency officials participating.*

Answer: I do not believe that the meetings that have been held between staff in the Office of Electric Reliability and EPA constitute an Inter-Agency Task Force as described in the subparts of your question.

Question 3. *Please describe all work being jointly performed by FERC staff, including work done in collaboration with EPA – whether in connection with an Inter-Agency task force or otherwise – regarding the potential impact of EPA regulations on the retirement of electric generating units and, to the extent such information has been developed, the specific type and characteristics of units that may face retirement as a consequence of such regulations.*

Answer: Based upon the information that I received from staff in the Commission's Office of Electric Reliability (OER), staff has shared public information with EPA, provided information to EPA on the types of studies that would be needed to address reliability concerns, and provided EPA with a set of questions about EPA's analytical results so that staff could better understand an ICF model that was used by EPA. Staff in OER told me that they made an effort not to create an impression that the Commission either endorses or disagrees with the study performed by EPA. According to OER staff, EPA's reliability analysis has been limited to generation adequacy assessments for 2015. EPA's analysis is apparently limited to the expected retirements caused by two of its rulings (does not include coal residuals, green house, clean water, and others). According to the information that I received from Commission staff, they have pointed out to EPA that a reliability analysis should explore transmission flows on the grid, reactive power deficiencies related to closures, loss of frequency response, black start capability, local area constraints, and transmission deliverability.

In addition, and also based upon the information that staff has told me, staff has indicated to EPA that the regional transmission planners would be best suited to run these studies. Commission staff has suggested that EPA interact with the ongoing initiatives at the grid operators known as "PJM" and "MISO" which are assessing the effect of projected retirements on their grids. Commission staff informed me that they believe that EPA needs to interact with regional transmission planners to determine the issues that may affect the regional grids, especially during the transition period when plants are retired and others are shut down to retrofit their facilities.

According to Commission staff, the ICF model used by EPA is a pipes and bubbles tool which assumes transmission deliverability is not an issue within the region. The ratings of the pipes (transfer limits) are apparently determined by consultants who analyze available transmission planning studies, historical OASIS postings and linear analysis. Based on the rating of the pipes, OER staff understands that the tool determines if firm transfers can be delivered from region to region as well as capacity additions needed to meet target reserve margins. OER staff believes that the ICF model does not consider certain reliability issues. According to OER staff, the ICF model could provide a potential scenario of the generation mix available in future years. OER staff believes that a transmission requirements study would still be needed to develop a transmission expansion plan for the potential generation mix that may result from the ICF tool.

Question 4. *Please describe FERC's efforts to explain the effect of potential retirements on electric reliability. If research, data, or analysis has been developed by or supplied to FERC, please provide it. If no analysis has been conducted, please explain why.*

Answer: The Commission has not engaged in efforts to explain the effect of potential retirements on electric reliability. The Commission has not issued any reports, orders, held a conference, or taken any action on this matter. While the Commission itself has not taken action, individual Commissioners have expressed their opinions. In that regard, on May 3, 2011, I discussed this matter with Gina McCarthy, Assistant Administrator for the Office of Air and Radiation, and some of her staff. On October 28, 2009, at Chairman Wellinghoff's invitation, I participated in a meeting with EPA, White House, Department of Energy, and others at a meeting with the White House Council on Environmental Quality.

While the Commission has not acted on this matter, the staff of the Commission has expressed its opinions. In response to why the Commission has not performed an "analysis", I believe that the Commission should consider whether it should issue a report containing a formal Commission analysis. If the Commission decides against the issuance of an analysis, then at minimum, the Commission should direct its staff to use its expertise to perform an analysis of the EPA's rules that could impact reliability of electricity --- and disclose that analysis for public comment --- and then hold a technical conference for public input.

Question 5. *Please describe fully FERC's powers to protect electric reliability in the event of plant retirements, and what measures FERC plans to take to ensure electric reliability or an explanation of why such measures have not been devised. Please provide the following assessments, or an explanation of why such assessments have not yet been devised:*

a. *an assessment of generation adequacy in the face of retirements of significant generating units in transmission-constrained areas;*
b. *an assessment of the effect of retirements of generating units in organized markets for energy and capacity (e.g. on prices and unit commitment); and,*
c. *a general assessment of the capacity to permit and construct new electric generation units in a timely manner such that electric supplies form retired plants are replaced and anticipated demand growth is met.*

Answer: To the extent that measures to ensure reliability have not been devised by Commission staff, then the Commission should direct its staff to develop such plans and take such measures. Given the importance of electric reliability, such plans and measures should be developed in an open process with opportunity for input from the general public.

Question 6. *The Clean Air Transport Rule specifically lists ensuring electric reliability as a "key guiding principle." Please describe any research, documentation or analysis FERC has provided EPA for this rule.*

Answer: To my knowledge, the Commission has not provided EPA with any research, documentation, or analysis of the Clean Air Transport Rule. However, individual Commissioners or the Commission staff may have provided their own opinions to EPA. I believe that the Commission should consider whether it should direct its staff to issue a report to the Commission on the Clean Air Transport Rule.

Question 7. *Regarding the Commission's FY 2010 Performance and Accountability Report to Congress, quoted above, and the staff analysis of electric reliability impacts referenced in the quotation, please describe or provide:*

a. *the study and all supporting materials including research;*
b. *a list of any other agencies involved in the production of the study with information on their involvement*
c. *actions FERC has taken or plans to take based on the study; and*
d. *how and where the study has been made public, or why it has not been released*

Answer: I believe that the Chairman will describe staff's work on this topic when the Chairman sends his response to you.

Question 8. *In your view, would compliance with EPA or other environmental regulations excuse a violation of FERC-approved electric reliability standards? If so, should the Commission refrain from imposing penalties for these violations?*

Answer: In my view, compliance with EPA or other environmental regulations would not necessarily excuse a violation of FERC-approved reliability standards. Every individual case should be addressed on its merits. For example, instead of excusing reliability standards, perhaps in some cases compliance with FERC-approved reliability standards should excuse non-compliance with EPA regulations. As stated above, I can be "fuel neutral" but I cannot be "reliability neutral".

Question 9. *Please assess whether FERC has sufficient statutory authority to protect electric reliability in collaboration with other federal entities that are undertaking rulemakings.*

Answer: At this time, the Commission seems to have sufficient statutory authority to protect electric reliability against actions that might be taken by EPA --- given my assumption that EPA, if provided with accurate information, will take actions that appropriately balance the importance of reliable electric supply against its statutory obligations. To assist the EPA, this Commission already has authority to issue reports, hold conferences, and seek information from the public on the reliability impacts of contemplated EPA rules. In addition, this Commission can describe the reliability impacts of the actions contemplated by the EPA by making appropriate submissions in the various rulemakings that are in process at EPA.

My views are shaped by the complexity and cost associated with shutting down a power plant --- and my concern that EPA be able to accurately model that process as part of its decision making. If a power plant is retired with inadequate notice, electricity can become less affordable and less reliable. Before a power plant is retired, the operator of the transmission grid must consider how to provide reliable electricity without that plant as part of the network.

A numerical example shows how cost and reliability need to be considered when a power plant is retired. That is, the operator of the transmission network could determine that a power plant can be retired only after utilities invest $50 million into upgrading the transmission system. Since they are long-lived transmission assets, those $50 million in assets would be expected to be in-service for some fifty years, which means that they would cost customers roughly $1 million a year (ignoring interest and present value). But in the interim, the power plant owner would be entitled to recover its costs of remaining open even after it had decided to shut its plant down. That cost could be $50 million to customers for one year of service --- a cost that could have been avoided had the $50 million in transmission upgrades been in service. Thus, while the transmission upgrades might only cost about $1 million each year for fifty years, the $50 million paid by consumers in one year to keep a plant open could make the retirement more costly than necessary. And this example doesn't even consider the cost of building a new power plant to replace the power that will be unavailable with the shut down.

In addition to this example, please see my concluding thoughts below, where I describe the recent plans to close certain generating units in the Philadelphia area that are known as Cromby and Eddystone.

Question 10. *Is FERC or any other agency, to your knowledge, soliciting or relying upon advice or assistance from any entity established pursuant to the Federal Advisory Committee Act?*

Answer: No, not to my knowledge.

Concluding Thoughts

I greatly appreciate your decision to send me these questions. Not only have you raised the visibility of this important issue, but your inquiry has prompted the Commission staff to better inform me on this topic.

- **The Critical and Complex Role of Reliability**

The recent and enduring heat wave that simultaneously impacted a large portion of the population of the United States underscores the essential and life-saving importance of electric reliability. With economic weakness and closed factories throughout the nation, you might have expected the available power plants to easily handle the heat wave. Yet the operators of the power grid relied on all of their available resources, including coal plants that are expected to be shut down because of EPA decisions, in order to ensure the reliability of the grid and the health and safety of the public.

My consistently expressed concern with EPA rulemakings has been the potential for a negative impact on reliability. I believe the system can absorb significant retirement of older coal-fired, oil-fired and natural gas-fired generation units. But it absolutely must be done in an orderly manner that does not impact our health and safety.

- **Timing of EPA Regulations and Utility Planning Horizons**

The timing of the EPA regulations does not conform to the relevant planning horizons in the electric sector of our economy, one of the most capital-intensive sectors of industry. Transmission lines and power plants are often planned over a ten-year period, and in consideration of the long-lived nature of assets that are expected to be in service for more than forty years. Compounding this situation is the fact that the United States has several distinct wholesale markets for electricity, including different types of markets that are broadly categorized as bilateral markets (covering many western and southeastern states) and organized markets (including markets in Texas, California, and many Midwestern and eastern states).

The rules for these electricity markets are not standardized. For reliability purposes, this exacerbates the challenge of conforming to EPA rules. Each region has different standards for planning for new power plants and transmission lines, and different standards for retiring an existing power plant. Thus, EPA and Commission staff must ensure that their analysis of reliability impacts is applicable in all regions of the nation, not just one or two.

In addition, some of the organized markets hold auctions of electric capacity three years in advance of the time when such capacity is needed. These auctions are generally designed to ensure that adequate generating capacity will be built when it is needed three years in the future. Other markets are considering equivalent types of "forward" capacity markets for the same reasons. A three-year advance cycle of generation procurement does not align with the EPA rules, as bidders into these markets may not know whether they can submit bids for all of their power plants, or if some of their power plants will need to retire within the next three years because of EPA regulations.

Prior to the most recent heat waves this summer, several studies concluded that the nation has enough excess capacity to absorb the retirement of surplus power plants. We should all be able to agree that surplus power plants can be retired if the remaining power plants are located where they can replace the power that will no longer be available. But looking at this issue from the perspective of the minimum number of power plants that is absolutely necessary doesn't answer the question of where power plants must be located. An older coal plant in a specific location may not provide a lot of energy to the grid, but it may be in a location with access to transmission lines or where its voltage support is critical for reliability.

- **The Cromby-Eddystone Example**

I have often cited the retirement of two electricity generating plants in the area surrounding Philadelphia as an example of how EPA air rules could impact the reliability of specific pockets of electricity load. In December 2009, Exelon provided notice to PJM of its intent to deactivate the Cromby and Eddystone units --- four fossil-fired generating units located in Southeastern Pennsylvania, all of which had operated for more than fifty years. Cromby Unit No. 1 is a 144 MW coal-fired unit; Cromby Unit No. 2 is a 201 MW peaking unit that is fueled by gas or oil. Eddystone No. 1 and No. 2 are both coal-fired units with a capacity of 279 MW and 309 MW, respectively.

Upon receipt of Exelon's notice, PJM conducted a deactivation study and determined that Cromby Unit No. 2 and Eddystone Unit No. 2 would be needed past their planned deactivation date to manage localized reliability issues pending completion of transmission system upgrades. Specifically, unless 18 identified transmission upgrades totaling $44 million were constructed and placed into service, the study revealed that the retirement of these generating units could have an adverse effect on reliability. Some of these upgrades were placed in-service earlier this year and the last of these upgrades are expected to be completed by June 2012.

As part of its obligation to ensure just and reasonable rates, the Commission conducted a proceeding that would determine the amount of compensation that would allow Exelon to recover its costs if it decided to keep the units operational. In that proceeding, Exelon explained that in 2009, the two generating units realized negative pre-tax cash flow of approximately $28 million when selling capacity, energy, and ancillary services at market rates. Exelon anticipated that future cash flows would be significantly negative because the units would require costly project investment to maintain their operability and because their dispatch would be limited due to environmental restrictions. Moreover, the generating units failed to clear in their regional capacity auctions, demonstrating that Exelon's costs to operate the units as capacity resources exceed the market price for capacity.

The proceeding settled prior to a formal hearing and the Commission ruled that the generating units could collectively charge customers about $82 million to continue operating before the transmission upgrades entered service.[2] The financial implications of at least this situation are clear: in order to retire these units, customers will pay at least $44 million for transmission upgrades, to be collected over the next forty to fifty years, and customers will also pay some $82 million to Exelon so that the power plants will be available for about a year, to be collected over the next year or so.

[2] As provided in the settlement, Eddystone Unit No. 2 received a twelve-month contract term, and Cromby Unit No. 2 received a seven-month term. If the transmission upgrades do not enter service on the expected date, the settlement provides for Exelon with an opportunity for additional compensation. *See* application of Exelon Corp. in FERC Docket No. ER10-1418, and Commission orders issued on September 16, 2010 and May 27, 2011: *Exelon Generation Co., LLC,* 132 FERC ¶ 61,219 (2010) *and Exelon Generation Co., LLC,* 135 FERC ¶ 61,190 (2011).

- **Better Data on Unit Retirements Now Available**

The uncertainty over proposed EPA rules has already impacted capacity markets. As described briefly above, some capacity auctions are held three years in advance. In PJM, the most recent (2011) forward capacity auction for 2014/2015 revealed that an increasing amount of generation from coal-fired plants is at risk of retirement; as 14% less capacity from coal plants cleared the auction when compared to the 2010 auction. PJM predicts that this trend of coal-fired generation retirements will continue into 2012 for its 2015/2016 auction.

PJM's RTO-wide capacity price for 2014/2015 substantially increased by 354 percent from the prior year's auction results. Increased prices in the PJM-West region showed much less price separation than in prior years from the PJM-East region. The rise in PJM-West capacity prices reflects the fact that, due to economic weakness, there are now fewer transmission constraints and congestion on the grid, which in turn allows for more affordable power to flow from west to east.

- **Recommendations**

Not only do I suggest that you and your Committee continue to follow and examine this issue, I respectfully offer several recommendations.

In speaking with reliability experts, one consistent recommendation is that the EPA needs to be involved in regional market stakeholder meetings where system planning is undertaken. Only then can EPA fully appreciate the location-specific impacts of its actions. I have heard from our Office of Reliability that EPA has not been involved to date.

In addition, I believe the federal government needs to convene an open and transparent process to assess the reliability implications of the EPA rules individually and in aggregate. EPA seems a natural choice, given that their rules would be the topic of the process. The Commission may also be a natural choice, given our responsibility for electric reliability. Regardless of which part of government convenes this open and transparent process, I would recommend that the North American Electric Reliability Corporation (NERC) be a major participant in any such process. Given the time constraints imposed by the courts on EPA, perhaps this process should have been initiated long ago. In any event, the feasibility of any court-imposed timeline is, at a minimum, worthy of consideration by Congress.

My answers to your questions also contain several recommendations. In response to question 4, I said that the Commission should consider whether it should issue a report containing a formal Commission analysis of potential retirements on electric reliability. If the Commission decides against the issuance of an analysis, then at minimum, the Commission should direct its staff to use its expertise to perform an analysis of the EPA's rules that could impact reliability of electricity --- and disclose that analysis for public comment --- and then hold a technical conference for public input.

And in response to question 5, I said that to the extent that measures to ensure reliability have not been devised by Commission staff, then the Commission should direct its staff to develop such plans and take such measures. Given the importance of electric reliability, such plans and measures should be developed in an open process with opportunity for input from the general public.

In response to question 6, I said that the Commission should consider whether it should direct its staff to issue a report to the Commission on the Clean Air Transport Rule.

- **Documents**

I am not providing documents responsive to this request at this time, as I will first have my personal staff review the documents that Commission staff is providing to you. If after that review I discover that I have additional documents in my possession that I believe are responsive, I will provide them to you.

- **Conclusion**

Finally, the impact of retiring power plants can be cushioned by making it easier to build the transmission lines that are needed to move power to customers. By building needed transmission, we can maintain the reliability of our nation's transmission network, while simultaneously improving consumer access to lower-cost power generation. Plus, a well-designed transmission network can allow efficient and cost-effective renewable resources to compete on an equal basis with traditional sources of power. I am always willing to express my thoughts on legislative changes that could ease the difficult process of building transmission.

I have no doubt that this nation is capable of retiring a substantial proportion of older and less efficient power plants that produce a disproportionate amount of air emissions. Nor do I doubt that power plants which emit too many pollutants should be eventually retired. But these retirements must be done in an orderly manner that does not threaten the reliability of electricity, which in turn affects our public health and safety.

Sincerely,

Philip D. Moeller

Mr. WHITFIELD. Thank you, Mr. Moeller.
Mr. Spitzer, you are recognized.

STATEMENT OF MARC SPITZER

Mr. SPITZER. My name is Marc Spitzer and I am a member of the Federal Energy Regulatory Commission. I thank you for the opportunity to appear before you today to discuss my views on the potential impacts of the Environmental Protection Agency's new and proposed power sector regulations on electricity reimbursement.

In the Energy Policy Act of 2005, Congress assigned FERC authority with respect to the reliability of the bulk power system. I remain committed, as do each of my colleagues, to ensuring the reliable operation of our Nation's electric grid. Reliable service of electricity is essential to the health, welfare and safety of the American people and necessary to serve our economy. However, I recognize that environmental protection laws and regulations are important to the well-being of our Nation as well. The United States has superb records in both environmental protection and electric reliability.

The issue before us today is how to best address the potential impacts of the EPA's new and proposed power sector regulations on the reliability of the Nation's bulk power system. I have several suggestions regarding the concerns raised.

First, FERC and the EPA need to be proactive to ensure reliability concerns are considered and addressed in any analysis by the EPA of its environmental regulations affecting utilities. To this end, I recommend that FERC and EPA continue their dialog but in a more formalized and expansion fashion. Given the potential impacts of EPA's proposed rules on the bulk power system, such coordination is critical to ensuring that EPA does not enforce its rules in a vacuum.

Second, the electric industry recognizes its obligation to comply with both environmental regulations as well as FERC-approved reliability standards and to plan their systems to reliably serve customers while complying with environmental requirements. It is the regulated entity, whether an individual utility or an independent system operator regional transmission organization, with better knowledge of its operations, needs and requirements that is in the best position to determine through its planning process how it will meet the various regulatory requirements that it faces. Decisions as to whether a unit is retired or retrofitted are typically made at the local or State level and State utility regulators generally play a significant role in resource adequacy decisions as well as compliance with EPA's proposed regulations. My concern is that regulated entities must have adequate time to plan their systems to comply with the rules that the EPA promulgates and with the FERC-approved reliability standards. Inadequate time to comply with the EPA's proposed regulations may result in users, owners and operations of the bulk power system being compelled by their government to choose between compliance with environmental laws or with FERC-approved reliability standards and then a face a penalty from one of these agencies. Regulated entities should not be put in a position of having to elect which agency's penalty they would rather face. Requiring public utilities to make such a Hobson's choice does not serve consumers and frankly is not good government.

As an example of one way to address this timing concern, in comments to the EPA certain of the ISO/RTOs propose a reliability safety valve that would permit a case-specific extension of time for compliance by a retiring generator needed to implement reliability solutions to replace the resource. I suspect it will be a rare situation when a regulated entity finds itself after having adequate time for planning in a position of having to choose between compliance with one regulator's rules over another's. It should be the duty of the regulators to work together and with the regulated entity to find a resolution that best assures reliable operation of the electric grid and compliance with environmental standards without violation of either regulator's rules.

Mr. Chairman, I thank you for the opportunity to provide my views on these important matters and I would be pleased to answer your questions.

[The prepared statement of Mr. Spitzer follows:]

Summary of Testimony of Marc Spitzer, Commissioner

Federal Energy Regulatory Commission

Before the House Subcommittee on Energy and Power

Of the Committee on Energy and Commerce

United States House of Representatives

September 14, 2011

Thank you for the opportunity to appear before you today to discuss my views on the potential impacts of the Environmental Protection Agency's (EPA) new and proposed power sector regulations on electric reliability.

First, the Federal Energy Regulatory Commission (FERC) and the EPA need to be proactive to ensure reliability concerns are considered and addressed in any analysis by the EPA of its environmental regulations affecting utilities. I recommend that FERC and the EPA continue their dialogue but in a more formalized and expansive fashion.

Second, it is the regulated entity (whether an individual utility or an Independent System Operator/Regional Transmission Organization), with better knowledge of its operations, needs and requirements, that is in the best position to determine through its planning process how it will meet the various regulatory requirements it faces.

Third, regulated entities must have adequate time to plan their systems to comply with the rules that the EPA promulgates and the FERC-approved reliability standards.

Testimony of Marc Spitzer, Commissioner

Federal Energy Regulatory Commission

Before the House Subcommittee on Energy and Power

Of the Committee on Energy and Commerce

United States House of Representatives

September 14, 2011

Mr. Chairman, Ranking Member Rush, and members of the Subcommittee:

My name is Marc Spitzer, and I am a member of the Federal Energy Regulatory Commission (FERC or Commission). I thank you for the opportunity to appear before you today to discuss my views on the potential impacts of the Environmental Protection Agency's (EPA) new and proposed power sector regulations on electric reliability.

In the Energy Policy Act of 2005, Congress assigned to FERC authority with respect to the reliability of the bulk-power system. I remain committed, as do each of my colleagues, to ensuring the reliable operation of our Nation's electric grid. Reliable service of electricity is essential to the health, welfare and safety of the American people and necessary to serve our economy. However, I recognize that environmental protection laws and regulations are important to the well-being of our Nation as well. The United States has superb records in both environmental protection and electric reliability.

The issue before us today is how to best address the potential impacts of the EPA's new and proposed power sector regulations on the reliability of the Nation's bulk-power system. I have several suggestions regarding the concerns raised. First, FERC and the EPA need to be proactive to ensure reliability concerns are considered and addressed in any analysis by the EPA of its environmental regulations affecting utilities.

To this end, I recommend that FERC and the EPA continue their dialogue but in a more formalized and expansive fashion. Given the potential impacts of the EPA's proposed rules on the bulk-power system, such coordination is critical to ensuring that EPA does not enforce its rules in a vacuum.

Second, the electric industry recognizes its obligation to comply with both environmental regulations and FERC-approved reliability standards and to plan their systems to reliably serve consumers while complying with environmental requirements. It is the regulated entity (whether an individual utility or an Independent System Operator/Regional Transmission Organization (ISO/RTO)), with better knowledge of its operations, needs and requirements, that is in the best position to determine through its planning process how it will meet the various regulatory requirements it faces. Decisions as to whether a unit is retired or retrofitted are typically made at the local or state level and state utility regulators generally play a significant role in resource adequacy decisions as well as compliance with the EPA's proposed regulations.

My concern is that regulated entities must have adequate time to plan their systems to comply with the rules that the EPA promulgates and with the FERC-approved reliability standards. Inadequate time to comply with the EPA's proposed regulations may result in the users, owners and operators of the bulk-power system being compelled by their government to choose between compliance with environmental laws or with FERC-approved reliability standards, and then face a penalty from one of the agencies. Regulated entities should not be put in the position of having to elect which agency's penalty they would rather face. Requiring public utilities to make such a Hobson's choice does not serve consumers and, frankly, is not good government. As an example of one way to address this timing concern, in comments to the EPA, certain of the ISOs/RTOs propose a "reliability safety valve" that would permit a case-specific extension of time for compliance by a retiring generator needed to implement reliability solutions to replace the resource.

I suspect it will be the rare situation when a regulated entity finds itself, after having adequate time for planning, in a position of having to choose between compliance with one regulator's rules over another's. It should be the duty of the regulators to work together, and with the regulated entity, to find a resolution that best assures reliable operation of the electric grid and compliance with environmental standards without violation of either regulator's rules.

I thank you for this opportunity to provide my views on these important matters. I am pleased to answer your questions.

Mr. WHITFIELD. Thank you, Mr. Spitzer.

Mr. Norris, you are recognized for 5 minutes.

STATEMENT OF JOHN R. NORRIS

Mr. NORRIS. Thank you, Mr. Chairman, Representative Rush and members of the subcommittee for inviting me here today. My name is John Norris and I am a commissioner with the Federal Energy Regulatory Commission.

As I stated in my written testimony submitted for today's hearing, I am sufficiently satisfied that the reliability of the electric grid can be adequately maintained as compliance with EPA's regulations is achieved.

Why do I say "sufficiently"? Because, frankly, I don't think we can ever be totally satisfied. Situations occur every day that impact the reliability of the electric grid. I believe the key is to be vigilant in protecting the grid from a myriad of vulnerabilities while being cognizant of the costs, while maintaining a reliable grid, and being able to promptly address new and emerging threats to reliability.

Nearly every decision involving reliability involves choices, choices between competing variables like cost, like level of reliability, environmental protections and more. The situation we face with the EPA rules is no different. That is why we have tools developed for meeting reliability and electricity supply challenges. So my colleagues have already cited the tool that you gave us with EPACT 2005 with the tools regarding reliability standards and the enforcement and penalty provisions that we have to oversee those standards with reliability. That is a tool we have going forward to address reliability concerns.

FERC has other places in place as does the DOE, as does the EPA and even the President to deal with reliability concerns going forward. Specifically under our jurisdiction at FERC, there are markets in place under our jurisdiction to provide market signals to the upcoming rules and costs associated with them can produce the most effective solutions to meet the resource needs for implementing these rules. These markets have fostered the development of new capacity resources, demand-side resources, new technologies like energy storage and more that currently are meeting our needs and will in the future. I have confidence these same markets will enable us to address the resource needs as a result of the EPA rules. That is not say there will not be challenges, and we may need to adopt new market rules to deal with situations that arise for specifically addressing the impact of these EPA rules but that is not new or a reason to delay the rules. The transmission planning regions and processes under FERC's jurisdiction that we have established with Rule 890, Order 890, and recent Order 1000 have put in place tools needed for transmission planning so that resources are there to address these types of challenges.

There have been numerous studies conducted regarding the impact of the EPA rules and the impact they have on resource adequacy and reliability. The biggest takeaway I have from these studies is there is a wide range of potential outcomes and a wide range that is driven by many different scenarios the studies have studied for the many possible rules EPA may determine or may make final.

But all of these studies reached the conclusion that there will adequate resources available. The challenge is, how do we make sure we apply the tools we have which we do every day in addressing reliability? These studies also revealed there area number of factors outside the EPA rules that are changing the makeup of our electric generation today largely driven by the market and largely driven by low natural gas prices as multiple studies have indicated. There is a transition occurring. We have a tremendous amount of our generation fleet today. Unfortunately, I would like to say unlike you and I, we can handle being members of AARP but I am not sure our electric fleet should be. We have an opportunity in this country to make a more efficient electric generation fleet to serve our needs going forward. This just presents another challenge of how we change that fleet out but it is happening right today irrespective of these EPA rules. With a marketplace as we have in place to make this transition most efficiently than what is already happening in the marketplace with natural gas and the change out of our generation, this is an opportunity to address health concerns and make our energy system more efficient for a more efficient economy in the future. We should not shy away from it. I don't think another study about potential outcomes or different scenarios will add to our ability to address reliability. We have tools in place today that if we use those tools, we continue to be diligent, we will be able to accommodate the impact of these EPA regulations.

So thank you for the opportunity to share with you today.

[The prepared statement of Mr. Norris follows:]

Summary of Testimony of Commissioner John R. Norris
Federal Energy Regulatory Commission

Before the House Subcommittee on Energy and Power
Of the Committee on Energy and Commerce
United States House of Representatives

September 14, 2011

Based on the information I have reviewed to date on EPA's regulations, I am sufficiently satisfied that the reliability of the electric grid can be adequately maintained as compliance with EPA's regulations is achieved.

I base my beliefs on a number of studies and other analyses that have been performed by a wide variety of entities, and the presence of tools available for addressing any issues that might arise as these rules are implemented. These studies and analyses, when viewed in conjunction with the available tools, reveal a path forward to addressing compliance with these rules while maintaining grid reliability.

FERC has two major sets of tools within our jurisdiction that enable us to help ensure reliability is not jeopardized as EPA's regulations are implemented. The first is our regulation of the competitive wholesale power markets. Providing certainty by finalizing the EPA requirements for generation resources will be key to ensuring that the market can respond. The second set of tools is the local and regional planning processes created under FERC Order No. 890, and the additional planning requirements now being developed to comply with recently issued FERC Order No. 1000.

The low projected price of natural gas represents an opportunity to transition from older, less efficient generation to newer, cleaner and more efficient generation in a reasonable manner. I consider the upgrading of our electric generation fleet to a higher level of efficiency as a positive economic outcome, in addition to the health benefits associated with the environmental outcomes from the EPA regulations.

With the information and the tools we have to mitigate potential reliability concerns, I have no reason to believe the EPA's regulations cannot be addressed to ensure reliability.

Testimony of Commissioner John R. Norris
Federal Energy Regulatory Commission
Before the House Subcommittee on Energy and Power
Of the Committee on Energy and Commerce
United States House of Representatives
September 14, 2011

Chairman Whitfield, Ranking Member Rush, and Members of the Subcommittee:

Thank you for inviting me to testify today regarding the impacts of the Environmental Protection Agency's (EPA) new and proposed power sector regulations on electric reliability.

My testimony is essentially an answer to question number 14 of the questions to which you requested my response. I view that question to be at the heart of why you asked me here today. The question is, "Are you fully satisfied that EPA's finalized, proposed, and anticipated power sector regulations will not adversely affect the reliability of the electric grid?"

In short, based on the information I have reviewed to date on EPA's regulations, I am sufficiently satisfied that the reliability of the electric grid can be adequately maintained as compliance with EPA's regulations is achieved.

I should begin with two important overarching points that are reflected in my testimony and answers to your written questions. First, I believe a reliable electric grid is extremely important to our economy and the safety of our citizens. In reliability, like many other elements of our electric power system, there is an intersection of physics, economics, policy, law and other factors. For that reason, I do not believe that we can ever claim 100 percent satisfaction that the marketplace, laws, regulations, and other variable factors affecting the private and public entities engaged in our electric system will not at some time impact the reliability of the electric grid. I take very seriously my responsibility to oversee and protect the reliability of our electric grid, but nearly every decision involves choices between competing variables like cost, level of reliability, environmental protection, and other factors. There is not a single answer, so I strive to balance the many factors to achieve a sufficient level of reliability. There are too many variables, however, to expect that lawmakers, regulators or industry can guarantee future outcomes. The key is having the appropriate tools available so we are prepared to deal with the myriad of situations that might occur.

Second, I believe the medical research and underlying science overwhelmingly substantiate that the emissions and effluents the Clean Air Act and Clean Water Act require the EPA to regulate have had and will continue to have harmful and costly impacts on the health of Americans, particularly the most vulnerable in our society, our children, elderly and those in poverty. It is important to remember that the proposed and final regulations that EPA is working toward are an effort by the agency to satisfy the requirements of these two statutes in the face of court orders requiring the agency to act expeditiously to uphold the law.

Turning to EPA's rules, I believe that the EPA has adequately addressed reliability concerns and its statutory obligations with the rules established to date and I have no reason to believe that it cannot continue to do so as it finalizes proposed rules. I base my beliefs first on the extensive analyses that have already been provided to date and are continuing to be performed by a wide variety of entities. There have been numerous studies by multiple entities that attempt to assess the reliability impact of EPA's proposed and final regulations. In my response to question 14, I have referred to or included seven publically-available assessments and analyses that I have found the most informative for reaching my conclusions. These studies have yielded a wide range of predictions or potential outcomes, due in large part to the differing assumptions they employ regarding the ultimate requirements EPA might adopt, the costs of compliance, and the relative economics of different types of generation. While the results of these studies do vary greatly, I have found none of them unreasonable, and none of them raise broad reliability concerns.

With these extensive macro level analyses already completed or ongoing, and given that I do not view them as revealing broad resource adequacy concerns, I believe the best course is for EPA to continue its work to finalize rules that it believes are both technically and economically achievable and adequately protective of public health. The Commission's best role is to utilize its tools and authorities to help manage the implementation of the EPA rules in the most efficient way possible. There are several tools available to help manage any reliability issues that might arise during compliance. The availability of these tools, when viewed in conjunction with the results of the macro level studies already produced, reveal a path forward to addressing compliance with these rules and allow us to guard against worst case scenarios.

For our part, FERC has two major sets of tools within our jurisdiction that enable us to help ensure reliability is not jeopardized as these regulations are implemented. The first is our regulation of the competitive wholesale power markets. Competition in the marketplace to meet future resource adequacy needs for maintaining grid reliability and adequate power supplies exists today at a level that gives me confidence in the marketplace as our first and best way to address the changes that will occur. These markets have fostered the development of new capacity resources, the development of demand side resources, and the emergence of technologies like electric storage to name a few. These market results, and our continuing oversight of those markets and the rules governing them, give me confidence in market solutions to most efficiently address the challenges presented by EPA's new regulations. To the extent changes to some market rules are needed as EPA's regulations are implemented, the Commission can quickly respond to such needs.

Second, the local and regional planning processes created under FERC Order No. 890, and the additional planning requirements now being developed to comply with FERC Order No. 1000, provide further tools to help address the challenges we may face to maintain reliability. Those processes provide a forum for stakeholders – industry, state commissions, and consumers alike – to consider both transmission and non-transmission solutions to ensure that the grid continues to meet reliability standards. Once EPA's regulations are finalized and generation owners are able to make their own decisions about the continued economic viability of their plants, these planning processes will be an important tool for addressing specific reliability impacts that may result from specific generator retirements.

To be sure, it is possible that individual generation unit retirements may reveal specific local reliability issues that need to be addressed. The tools within FERC's jurisdiction that I note above provide opportunities to address these issues. However, there may be specific instances where compliance flexibility is necessary to ensure that local reliability is maintained. EPA has strongly indicated that electric reliability is an important consideration, and I have no reason to believe that they will not provide targeted compliance flexibility where needed to maintain reliability.

I would also add that it should come as no surprise that the many coal and oil generation facilities at issue in this discussion were likely to be retired in the near future regardless of EPA's current rulemakings. The Congressional Research Service notes that "[m]any of these plants are inefficient and are being replaced by more efficient combined cycle natural gas plants, a development likely to be encouraged if the price of competing fuel – natural gas – continues to be low, almost regardless of EPA rules".[1] It is evident that low natural gas prices are presently sending a strong market signal to retire many of these facilities. Price competition from natural gas as a fuel source is driving retirement of coal plants even in the absence of environmental regulations. In addition, the projection of low natural gas prices for the foreseeable future means we have an

[1] Congressional Research Service, "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?", Summary (August 8, 2011).

opportunity to now transition from older, less efficient generation to newer, cleaner and more efficient generation at a cost to society much lower than it would be otherwise. I consider the upgrading of our electric generation fleet to a higher level of efficiency as a positive economic outcome, in addition to the health benefits associated with the environmental outcomes from the EPA regulations.

The most common request I hear from regulated entities is the need for certainty in regulations so businesses can make the most efficient decisions for investment in what is a capital intensive industry. A significant percentage of existing assets in the electric utility industry are over 40 years old, but with uncertainty in future environmental requirements, it is difficult to make decisions regarding when to retire those assets and what to replace them with. Delaying the implementation of EPA regulations to implement the Congressionally-mandated requirements of the Clean Air Act and Clean Water Act will only increase the level of uncertainty already existing in the electric generation sector. One more national study by FERC or any other entity is not going to provide any more certainty or information than we already have from the studies, comments and analyses that have already been produced in EPA's rulemaking process.

Providing certainty regarding the environmental requirements that generation resources will be required to meet will be key to ensuring that the market can respond. Historical data suggests that when called upon, the electric utility industry can bring significant amounts of new generation capacity online when conditions warrant. As the Congressional Research Service notes, from 2000 to 2003, over 200 GW of new generation capacity was added, "far more than any of the analyses suggest will be needed in the 2011-2017 timeframe".[2] My experience in Iowa also suggests to me that with regulatory certainty, industry will meet the challenge. After advanced ratemaking principles were established by lawmakers and regulators to reduce regulatory uncertainty associated with investing in new generation capacity, the state's utilities responded, constructing significant new in-state resources.

Thus, with the information we have in hand and the tools available to mitigate any potential reliability concerns, I believe we can manage the integration of these new environmental requirements into the power system while maintaining a reliable electric grid.

[2] Congressional Research Service, "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?" at 34 (August 8, 2011).

Congressional
Research
Service

EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?

James E. McCarthy
Specialist in Environmental Policy

Claudia Copeland
Specialist in Resources and Environmental Policy

August 8, 2011

Congressional Research Service
7-5700
www.crs.gov
R41914

CRS Report for Congress
Prepared for Members and Committees of Congress

Summary

Given the central role of electric power in the nation's economy, and the importance of coal in power production, concerns have been raised recently about the cost and potential impact of regulations under development at the Environmental Protection Agency (EPA) that would impose new requirements on coal-fired power plants. Six of the rules, which have drawn much of the recent attention, are Clean Air Act regulations. Two others are Clean Water Act rules, and one is a Resource Conservation and Recovery Act rule. The majority are expected to be promulgated over the next 18 months. All together, these rules have been characterized by critics as a regulatory "train wreck" that would impose excessive costs and lead to plant retirements that could threaten the adequacy of electricity capacity (i.e., reliability of supply) across the country, especially from now through 2017.

Although some question why EPA is undertaking so many regulatory actions in such a short time-frame, supporters of the regulations assert that it is decades of regulatory delays and court decisions that have led to this point, resulting in part from special consideration given electric utilities by Congress under several statutes. Further, several of the current regulatory developments have been under consideration for a decade or longer, or are being reevaluated after an earlier action was vacated or remanded to EPA by the courts. The regulations are supported by proponents and EPA as having substantial benefits for public health and the environment.

Recent reports by industry trade associations and others have discussed potential harm of EPA's prospective regulations to U.S. electricity generating capacity, with emphasis on coal-fired generation. One of these reports, by the Edison Electric Institute, which represents investor-owned utilities, has attracted considerable attention by depicting a timeline in which multiple rules would take effect more or less simultaneously over the next five years. Congress has shown significant interest in these issues, and bills have been introduced that would de-fund or restrict EPA's ability to develop rules, and which would legislate new regulatory analytic requirements. Tbis report describes nine rules in seven categories that are at the core of recent critical analyses, with background on the rule and its requirements and, where possible, a discussion of the rule's potential costs and benefits.

The EEI and other analyses discussed here generally predate EPA's actual proposals and reflect assumptions about stringency and timing (especially for implementation) that differ significantly from what EPA actually may propose or has promulgated. Some of the rules are expected to be expensive; costs of others are likely to be moderate or limited, or they are unknown at this point because a rule has not yet been proposed. Rules when actually proposed or issued may well differ enough that a plant operator's decision about investing in pollution controls or facility retirement will look entirely different from what these analyses project. Further, promulgation of standards is not the end of the road: court challenges are likely, potentially delaying implementation for years, and even when final, EPA rules must be adopted by states and implemented over time through state-issued permits.

The primary impacts of many of the rules will largely be on coal-fired plants more than 40 years old that have not, until now, installed state-of-the-art pollution controls. Many of these plants are inefficient and are being replaced by more efficient combined cycle natural gas plants, a development likely to be encouraged if the price of competing fuel—natural gas—continues to be low, almost regardless of EPA rules.

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Introduction

Given the central role of electric power in the nation's economy, and the importance of coal in power production, concerns have been raised about the cost and potential impact of numerous regulatory actions that would impose new requirements on coal-fired power plants. In the summer of 2010, for example, the Edison Electric Institute (EEI), which represents the nation's investor-owned electric utilities, prepared a chart, "Possible Timeline for Environmental Regulatory Requirements for the Electric Utility Industry," which is reproduced here as **Figure 1**. Using color-coded categories, the chart identified rules under development at the U.S. Environmental Protection Agency (EPA) and depicted a schedule for development and implementation of the rules between 2008 and 2017.

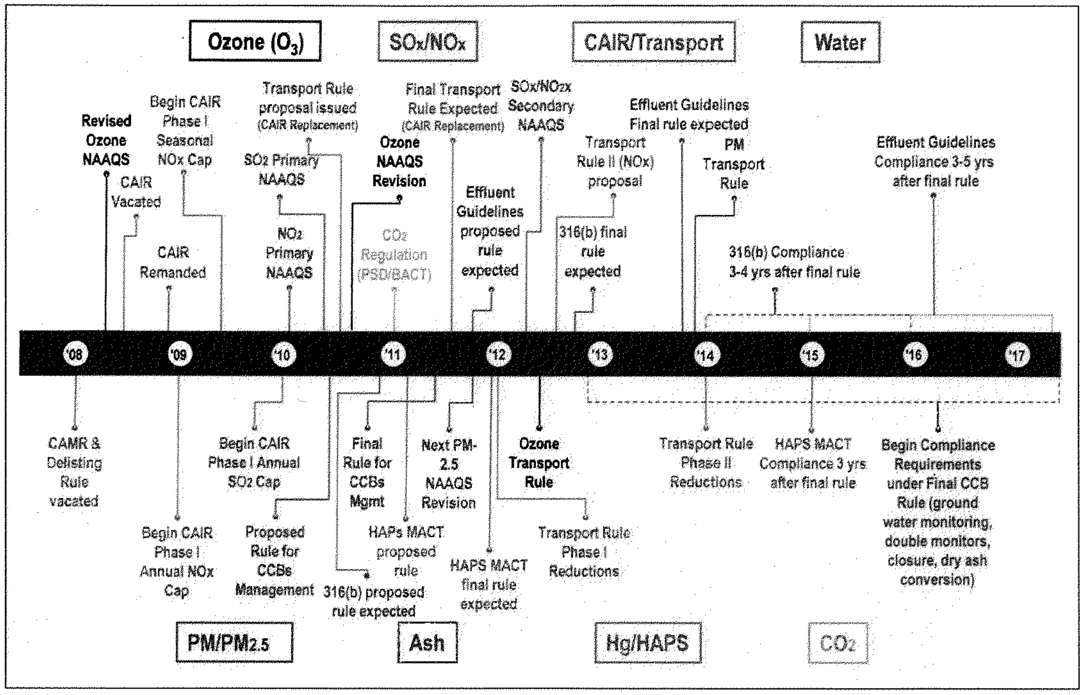
The rules identified by EEI were:

- the Cross-State Air Pollution Rule, and its predecessor, the Clean Air Interstate Rule (identified as "CAIR/Transport" on the timeline), which would establish cap-and-trade programs for utility emissions of sulfur dioxide and nitrogen oxides;
- Maximum Achievable Control Technology emission standards for mercury and other hazardous air pollutants, a rule generally referred to as the "Utility MACT" ("Hg/HAPS" on the timeline);
- National Ambient Air Quality Standards (NAAQS) for ozone, sulfur dioxide, nitrogen dioxide, and particulate matter ("Ozone," "SOx/NOx," and "PM/$PM_{2.5}$" on the timeline);
- regulation of greenhouse gas emissions ("CO_2" on the timeline);
- cooling water intake regulations ("316(b)" on the timeline);
- clean water effluent guidelines (identified under "Water" on the timeline); and
- coal combustion waste management rules ("Ash" or "CCBs Management").

EEI subsequently produced a report, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, which concluded that new EPA regulations would cause the unplanned retirement of 17 to 59 gigawatts (GW) of coal-fired electric capacity (5.4% to 18.8% of the current coal-fired total of about 315 GW) by 2015, and would require incremental capital expenditures of $85 billion to $129 billion.[1]

[1] ICF International, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, Final Report, prepared for the Edison Electric Institute, January 2011, available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf. Hereinafter referred to as the "EEI report."

Figure 1. EEI's Timeline for Environment Requirements for the Electric Utility Industry



Source: Edison Electric Institute, http://www.eei.org/whatwedo/PublicPolicyAdvocacy/TFB%20Documents/100525SheaCongressCoalImpacts.pdf (Figure 7).

EEI is not the only group to have focused on EPA's prospective regulations. The American Legislative Exchange Council (ALEC) picked up EEI's chart, added to it the separate EPA rules that will affect industrial and commercial boilers, and labeled it "EPA's Regulatory Train Wreck." The National Mining Association also refers to "EPA's Regulatory Train Wreck" in materials that it distributes, and the North American Electric Reliability Corporation (NERC), in an October 2010 Special Reliability Assessment, concluded that implementation of four EPA rules could result in a loss of up to 19% of fossil-fuel-fired steam capacity in the United States by 2018, with the potential for "significantly deteriorating future … system reliability."[2] In addition to these, a large number of other analyses have been prepared by other policy and research groups; some are similarly critical of EPA's rules, while others counter or rebut the criticisms. Many of these reports are identified below in **Appendix B**.

The "train wreck" charts and related studies have been widely circulated on Capitol Hill, where they have stimulated concern. Several bills aimed at reducing the regulatory burden or requiring additional analyses of the combined rules' impacts have been introduced, as have proposals to modify or delay implementation of specific EPA rules. As discussed below in "Legislation," as of August 2011, three of these bills had passed the House.

Opponents of these bills maintain that regulation of the affected plants is overdue. Coal-fired power plants are major sources of pollution; many are decades old; and regulation of their emissions, effluent, and waste has lagged that of other industries.

Coal's Place in Electric Power Production

Coal fueled 44.6% of the nation's electric power in 2009. This was a decline from 52% in 2000, but coal is still the electric power industry's dominant fuel source (as shown in **Figure 2**).

Many coal-fired electric generating units, along with most nuclear and hydroelectric plants, provide what is called "base-load" power. Many of the plants run 24 hours a day and provide the relatively cheap power that is the foundation of electric service. (Other plants, known as peaking plants, are brought into service at times of peak demand. Peaking plants tend to have higher operating costs, but since they operate for short periods of time, the higher cost is of less concern.)

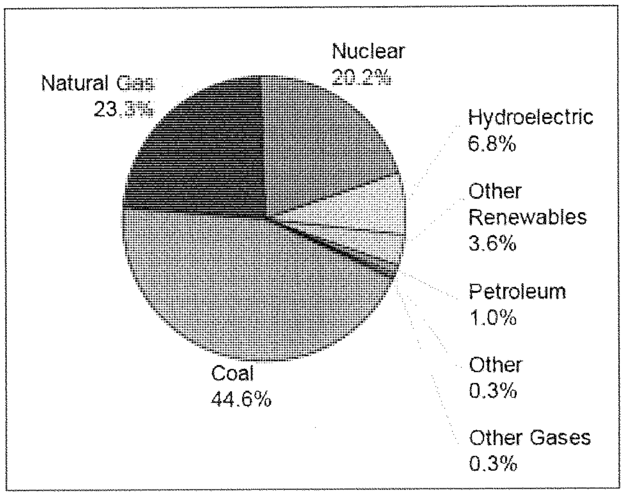
Low Cost

Coal-fired power has been cheap for multiple reasons. The average coal-fired power plant is more than 40 years old and its capital cost fully amortized, whereas many natural gas plants (the second largest source, producing about 23% of the nation's electricity) have been built in the last 10 years. Coal itself (i.e., the fuel) is abundant and cheap: as shown in **Figure 3**, its price—expressed in dollars for the same energy content, i.e., dollars per million Btu—has sometimes been less than

[2] North American Electric Reliability Corporation, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October 2010, pp. I and IV, http://www.nerc.com/files/EPA_Scenario_Final.pdf. Hereinafter referred to as the "NERC report." NERC is an independent organization, founded by the electric utility industry, that conducts periodic, independent assessments of the reliability and adequacy of the bulk power system in North America.

one-fourth the cost of natural gas, its main competitor. Averaged over a 12-year period, coal cost less than one-third as much as gas.

Figure 2. U.S. Electric Power, 2009, by Fuel Type

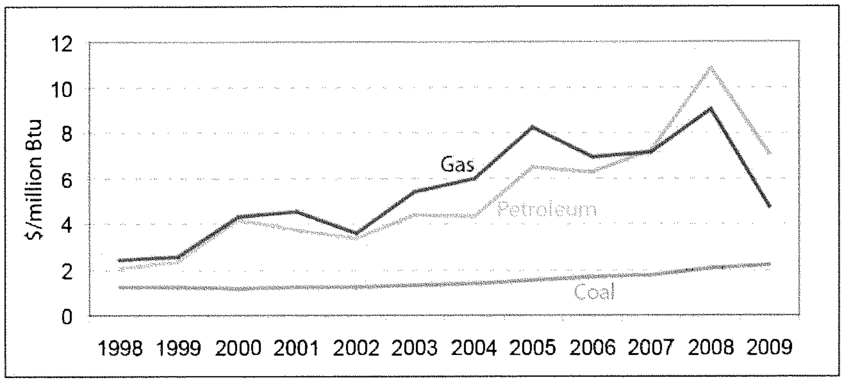


Source: U.S. Energy Information Administration, *Electric Power Annual, 2009*, April 2011, Table 2.1.

Of course, other factors also affect the price of power, including the efficiency with which the plant converts fuel into electric power, maintenance costs, and the cost of operating the unit—which, in the case of coal must include costs for removal and management of ash. But, in general, these factors did not outweigh coal's basic cost advantage until the advent of natural gas combined cycle technology in the 1990s.

Figure 3. Average Cost of Fossil Fuels for the Electric Power Industry, 1998 through 2009

($/million Btu)

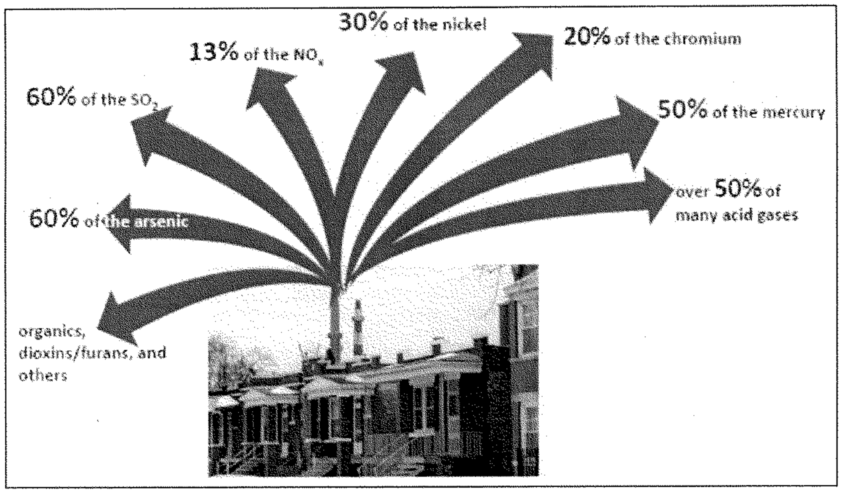


Source: U.S. EIA, Electric Power Annual 2009, April 2011, Table 3.5.

Clean Air Act Exceptions

Besides the age of the plants and the cost of the fuel, a third factor that has resulted in lower cost is that many of the coal-fired plants, particularly the older ones, have been allowed to operate with little in the way of pollution control equipment. Coal is an inherently "dirty" fuel. Burning it produces sulfur dioxide (SO_2), nitrogen oxides (NOx), particulates, mercury, acid gases, and other pollutants, in greater abundance than other fossil fuels. As shown in **Figure 4**, coal-fired power is *a* major or *the* major source of the air emissions of many of these pollutants.

Figure 4. Emissions from Fossil-Fueled Power Plants as a Percent ofTotal U.S. Air Emissions



Source: U.S. EPA, "Reducing Toxic Pollution from Power Plants," March 16, 2011, p. 6.

Note: The figure includes emissions from oil-fired units as well as coal-fired, but oil-fired units account for only 1% of U.S. electric generation. Air emissions are not necessarily the major source of exposure for each of these pollutants.

Despite the industry's emissions, the structure of the Clean Air Act has allowed many of the older coal plants to operate with minimal controls. The statute's focus is on new sources of pollution (including major modifications of existing plants). Under Sections 165 and 169 of the act, new plants and major modifications are required to install the Best Available Control Technology (BACT) in order to obtain an operating permit. Other plants (so-called "grandfathered plants") are not required to have best available controls, unless subject to state or local requirements needed to address local air quality. The majority of the grandfathered plants are coal-fired.

In addition, the act's major requirements for existing power plants, the acid rain program and the NOx control program (generally known as the "NOx SIP call"), have both been cap-and-trade programs. These allowed companies to decide how they wanted to meet system-wide emission caps: by switching to lower sulfur fuels, by installing the best control equipment on a few plants, by operating their dirtiest plants less frequently, or by purchasing allowances from facilities that had over-complied. Since controls weren't required on each individual plant, many of the older plants could keep running without them.[3]

[3] Power plant operations also can affect water quality in several ways, and EPA is developing regulations to strengthen requirements for both water intake and water effluent. These regulations affect a broader range of power plants, however, including natural gas and nuclear, as well as coal-fired.

The "Train Wreck" Rules

General Observations

Burning coal to generate electricity can affect the environment in a number of ways, producing air pollution, water pollution, and solid waste residuals. As reflected in the EEI timeline and other analyses, EPA's regulatory activities touch on all of these, although much of the recent critical attention has focused on air pollution.

EEI's chart contains 32 entries covering a 10-year period, 2008-2017. Not all of these entries represent actions by the Obama Administration's EPA. Of the first seven, for example, three are court decisions vacating and remanding Bush Administration EPA rules, and the other four are rules that were promulgated during the Bush Administration with implementation scheduled for 2009 or 2010. Because the Bush Administration's Clean Air Interstate Rule (CAIR) was the subject of two court decisions and was designed to be implemented in phases, it gets numerous entries: three entries for implementation (for its seasonal NOx cap), its annual NOx cap, and its SO_2 cap) and two for the court decisions that vacated and remanded it.

CAIR and its replacement rules are the extreme example of repetition on the "train wreck" charts, accounting for 10 of the 32 total entries, but most of the other rules on the chart have at least three entries—for proposal, promulgation, and implementation. Only implementation imposes an actual burden on the regulated community. Thus, the chart tends to exaggerate the regulatory burden through repetition.

The timeline also treats as imminent the promulgation of rules that may not be so. For example, the coal combustion waste rule, which has been the object of some concern, was authorized in the Solid Waste Disposal Act Amendments of 1980. The legislation required that EPA conduct a study of whether such waste should be considered hazardous waste and report to Congress before taking regulatory action. EPA has conducted numerous studies over the three decades since then and proposed to regulate the management of the waste in June 2010. Since then, however, the agency has stated that it does not anticipate promulgating a final rule in 2011, leaving uncertain when a rule will be promulgated. The EEI timeline assumed promulgation in 2011 with compliance five years later.

Nevertheless, it is safe to say that several major rules under development at EPA are due to be promulgated within the next 18 months and will affect coal-fired power plants, as shown in **Table 1**. Some of them are expected to be expensive; the costs of others are likely to be moderate or limited, or they are unknown at this point because a rule has not yet been proposed.

Table 1. Timing of EPA Rules and Impacts on Coal-Fired Utilities

Rule or Standard	Final Rule	EPA Estimate of Costs/Impacts[a]
Cross-State Air Pollution Rule	Finalized July 6, 2011	$2.4 billion/year[b]
Utility MACT Rule	Expected November 16, 2011	$10-$11 billion/year
National Ambient Air Quality Standard (NAAQS) for sulfur dioxide	Promulgated June 22, 2010	$1.5 billion/year for all sources, but limited impact on electric generating units (EGUs)[a]
NAAQS for ozone	Expected July 2011	$19-$25 billion/year for all sources but limited impact on EGUs[a]
NAAQS for particulate matter	Not yet proposed; expected in 2012	Unknown
New Source Performance Standards for Greenhouse Gases	Not yet proposed; expected May 26, 2012	Unknown
Cooling Water Intake Structure Rule	Expected July 27, 2012	$319 million/year
Clean Water Effluent Limitation Guidelines Rule	Not yet proposed; expected January 31, 2014	Unknown
Coal Combustion Waste Rule	Expected 2012 or later	$587 million-$1.5 billion/year

Source: Compiled by CRS.

a. Costs as estimated by EPA. See text for discussion of costs and impacts of specific rules.

b. Of the $2.4 billion annual cost, $1.6 billion is attributed to the Clean Air Interstate Rule (CAIR), a 2005 rule that the Cross-State Rule is replacing.

This report will discuss each of the rules identified on EEI's timeline individually; but before discussing individual rules, a few general statements are in order.

First, most of these rules have been a long time in the making. As noted, the coal combustion waste rule is the result of legislation passed in 1980; another rule, the utility air toxics rule (or "Utility MACT"), which appears to be the most costly of the rules thus far proposed, is required by the Clean Air Act Amendments of 1990. Some may question why EPA is undertaking so many regulatory actions at once, but it is the decades of regulatory inaction that led to this point that strike other observers.

The inaction stemmed in large part from special consideration given electric utilities by Congress: both the Clean Air Act and the Solid Waste Disposal Act required special studies and reports to Congress before EPA could set standards for certain pollutants emitted or wastes disposed by electric utilities. Meanwhile, other industries that emitted the same pollutants or similar wastes (e.g., municipal solid waste incinerators and medical waste incinerators, and any industry generating hazardous waste) have been subject to more stringent emission controls or waste management standards for a decade or more.

Second, as we have noted in an earlier report on EPA regulations,[4] both the legislative authority for these rules and, in most cases, the development of the rules themselves predate the current Administration. With the exception of greenhouse gas emission rules, all of the rules discussed below began development under the Bush Administration or earlier, including several that were promulgated under that Administration and subsequently were vacated or remanded to EPA by the courts. The Cross-State Air Pollution Rule, the Utility MACT rule, and the Cooling Water Intake rule, for example, fit that description. Other EPA actions, such as the Obama Administration's reconsideration of the ozone National Ambient Air Quality Standard, have actually delayed for several years implementation of Bush Administration rules that would have strengthened existing standards. Each of these actions is described in more detail below.

Third, one criticism highlighted by the EEI and others of EPA's pending and upcoming rules is the impact of multiple requirements. The critics point out that, although EPA conducts detailed economic impact analyses of individual rules, the CAA and other federal environmental laws do not provide a mechanism or require that the agency analyze cumulative impacts, including jobs. Viewed separately, they argue, a particular rule may have limited economic impact, while the second, third, or fourth rule that takes effect more or less simultaneously may drive the power plant operator to decide to retire a given facility. As discussed in this report, such decisions are highly case-specific, involving unique considerations and potentially mitigating factors.

The following sections of this report describe seven rules or categories of rules that are the core of the "train wreck" debate, with background on the rule, information on its requirements (for those rules that have been proposed or promulgated), and where possible, a discussion of the rule's potential costs and benefits. We also examine two of the studies—those of the electric industry's trade association (EEI) and the North American Electric Reliability Corporation—that have attempted to estimate their cumulative economic impacts.

Cross-State Air Pollution (Clean Air Transport) Rule

The Cross-State Air Pollution Rule (hereinafter, the "Cross-State Rule") replaces EPA's major clean air initiative under the Bush Administration, the Clean Air Interstate Rule (CAIR). CAIR was promulgated in 2005, but was vacated and remanded to the agency by the D.C. Circuit Court of Appeals in 2008.[5] On appeal, the court left the rule in place until such time as EPA promulgated a replacement. The agency proposed the replacement August 2, 2010,[6] and it finalized the rule July 6, 2011.[7]

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[4] CRS Report R41561, *EPA Regulations: Too Much, Too Little, or On Track?*, by James E. McCarthy and Claudia Copeland.

[5] The promulgated rule was published at 70 *Federal Register* 25162, May 12, 2005. The court decision was North Carolina v. EPA, 531 F.3d 896 (D.C. Cir. 2008).

[6] U.S. Environmental Protection Agency, "Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule," 75 *Federal Register* 45210, August 2, 2010.

[7] The final rule has not appeared in the *Federal Register* as of this writing, but a pre-publication copy as well as explanatory and background material can be found on EPA's website at http://www.epa.gov/crossstaterule/actions.html. When proposed in August 2010, the Cross-State Rule was referred to as the Clean Air Transport Rule. The name change to "Cross-State Rule" occurred late in the development of the final rule. As a result, many of the explanatory materials, including the final Regulatory Impact Analysis, refer to the "Transport Rule."

Both CAIR and its replacement, the Cross-State Rule, are designed to control emissions of air pollution that cause air quality problems in downwind states. The original, Bush-era rule did so by establishing region-wide cap-and-trade programs[8] for SO_2 and NOx emissions from coal-fired electric power plants in 28 Eastern states, at an estimated annual compliance cost of $3.6 billion in 2015.[9] CAIR covered only the eastern half of the country, but since most of the coal-fired generation capacity lacking emission controls is located there, EPA projected that nationwide emissions of SO_2 would decline 53% and NOx emissions 56% by 2015, as compared to nationwide emissions from electric generating units (EGUs) in 2001.

The replacement rule, finalized July 6, 2011, is a modified cap-and-trade rule. It would allow unlimited trading of allowances within individual states; interstate trading would be allowed so long as a state remained within 18%-21% of its emissions caps. Limiting interstate trading would address the D.C. Circuit's ruling, which found CAIR's interstate allowance trading program unlawful.

The rule applies to 28 states (adding Oklahoma, Kansas, and Nebraska to the 28 covered by CAIR, but removing Connecticut, Delaware, and Massachusetts from the CAIR group). Its annual compliance cost is estimated at $3.0 billion in 2012 and $2.4 billion in 2014.[10]

The Cross-State Rule would leave the CAIR Phase 1 (2009-2010) caps in place and would set new limits replacing CAIR's second phase in 2012 and 2014, up to three years earlier than CAIR would have done. The 2012 and 2014 requirements place particular emphasis on SO_2—emissions of which would decline to 2.4 million tons in the covered states (73% below 2005 levels) in 2014.

To insure that the Cross-State Rule is implemented quickly, EPA is promulgating a Federal Implementation Plan (FIP) for each of the states: the FIP specifies emission budgets for each state based on controlling emissions from electric power plants. States may develop their own State Implementation Plans and may choose to control other types of sources if they wish, but the federal plan will take effect until the state acts to replace it.

The CAIR Phase 1 rules already appear to be having substantial effects. In August 2010, EPA reported that emissions of SO_2 had declined sharply in both 2008 and 2009: in the latter year, emissions from fossil-fueled power plants in the lower 48 states (at 5.7 million tons) were 44% below 2005 levels. NOx emissions from the same sources declined to 1.8 million tons in 2009, a

[8] A cap-and-trade system sets a declining national cap on emissions and allocates emission allowances that can be bought and sold on open markets.

[9] 70 *Federal Register* 25306, May 12, 2005.

[10] These cost estimates include $1.6 billion in annualized costs already incurred to comply with Phase 1 of CAIR. EPA estimates the additional cost of the Cross-State Rule at $1.4 billion in 2012 and $0.8 billion in 2014. The 2014 cost of compliance with the Cross-State is less than that estimated for 2012 or for final implementation of CAIR in 2015 because the Regulatory Impact Analyses for the two rules use different base years for comparison. As the agency's RIA for the Cross-State Rule notes, "The base case in this RIA assumes that CAIR is not in effect, but does take into account emissions reductions associated with the implementation of all federal rules, state rules and statutes, and other binding, enforceable commitments finalized by December 1, 2010, that are applicable (sic) the power industry and which govern the installation and operation of SO_2 and NOx emissions controls in the timeframe covered in the analysis." Thus, the base with which control requirements are compared already accounts for some reductions realized since the original CAIR rule was promulgated. See U.S. EPA, Office of Air and Radiation, *Regulatory Impact Analysis (RIA) for the final Transport Rule*, June 2011, p. 244, at http://www.epa.gov/crossstaterule/pdfs/FinalRIA.pdf. Hereafter, "Cross-State Rule RIA."

decline of 45% compared to 2005.[11] The reductions occurred well in advance of CAIR's compliance dates: in fact, for both SO_2 and NOx, the affected units had achieved about 80% of the required 2015 reductions six years ahead of that deadline. Further reductions of both SO_2 and NOx can be expected as Phase 1 takes effect. The Cross-State Rule would build on these reductions.

As noted earlier, EPA estimated that compliance with the rule will cost the power sector $2.4 billion annually when fully effective. It expects the benefits to be 50 to almost 120 times as great—an estimated $120 billion to $280 billion annually. The most important benefit would be 13,000 to 34,000 fewer premature deaths annually. Avoided deaths and other benefits would occur throughout the East, Midwest, and South, according to EPA, with Ohio and Pennsylvania benefitting the most.[12]

Both EEI and NERC included the Cross-State Rule in their analyses, and their estimates of the rule's cost and the impact on coal-fired power do not appear to differ greatly from those of EPA, particularly in the "train wreck" years, from now until 2017. NERC, for example, concluded that the Cross-State Rule as proposed (then referred to as the "Transport Rule") would lead to 2.9 GW of deratings[13] or retirements by 2015.[14] This would represent less than 1% of coal-fired capacity, and less than 0.3% of all EGU capacity. EPA, by comparison, projects that 4.8 GW of coal-fired capacity would be uneconomic to maintain as a result of the rule.[15]

EEI's analysis stated that it used EPA's Integrated Planning Model assumptions with "no additional controls for SO_2-specific compliance" and with EPA's preferred option for NOx compliance through 2017. With the same assumptions and the same model, EEI's projected compliance costs should not differ from those of EPA.

For the years after 2017, however, EEI's analysis did differ from that of EPA: it assumed that selective catalytic reduction (SCR) would be required on all units to reduce NOx emissions. This *would* impose additional cost, since about 54% of coal-fired capacity will not have installed SCR to comply with the Cross-State Rule's 2014 requirements, according to EPA.[16] These costs are speculative: to date, EPA has not proposed additional post-2014 requirements, and, as a result, the agency has not estimated costs of compliance or a schedule for implementation of any future pollution transport regulations.[17]

[11] Data are from EPA's "2009 Acid Rain Program Emission and Compliance Data Report," August 11, 2010, at http://www.epa.gov/airmarkets/progress/ARP09.html. Some of the emission reduction was the result of the recession, which resulted in a decline in electric power generation of 5% from 2007 to 2009. Coal use for electricity generation declined even more (11% from 2007 to 2009).

[12] U.S. EPA, Office of Air and Radiation, "Final Air Pollution Cross-State Air Pollution Rule," Overview Presentation, undated, pp. 12-14, at http://www.epa.gov/crossstaterule/pdfs/CSAPRPresentation.pdf.

[13] "Derating," in these analyses, refers to the loss of available capacity because of the power needed to operate the pollution control equipment.

[14] NERC report, p. 20.

[15] Cross-State Rule RIA, p. 262.

[16] Cross-State Rule RIA, p. 259.

[17] Given the need to meet the more stringent ambient air quality standard (NAAQS) requirements, especially those for ozone and PM (described below), which EPA is expected to propose or promulgate this year, the agency stated its intention to propose a further set of requirements addressing interstate transport of air pollution in 2011. (These potential further rules appear on EEI's chart as "Transport Rule II (NOx) Proposal" and "PM Transport Rule.")

To summarize, CAIR and its replacement, the Cross-State Air Pollution Rule, would impose annual costs in the $2 billion to $3 billion range on previously uncontrolled coal-fired electric generating units. Although these are significant costs, the industry has already complied with Phase 1, which was the most ambitious of the rules' requirements. Prompted by the ability to generate tradable allowances, the industry complied well ahead of schedule. The final version of the Cross-State Rule allows additional allowance trading as compared to the proposed rule, giving EGUs additional flexibility in determining how to comply and lowering compliance costs.

Mercury and Air Toxics Standards/Utility MACT

In 2005, EPA promulgated regulations establishing a cap-and-trade system to limit emissions of mercury from coal-fired power plants. Coal-fired electric generating units (EGUs) account for about half of U.S. mercury emissions. Mercury is a potent neurotoxin that can harm health (principally delayed development, neurological defects, and lower IQ in fetuses and children) at very low concentrations.[18]

The mercury cap-and-trade rules promulgated in 2005 were a change in policy by EPA. All previous sources of mercury subject to emission standards had been required to meet plant-specific Maximum Achievable Control Technology (MACT) standards under CAA Section 112.[19] Section 112 sets out very detailed requirements for MACT standards, including a list of the pollutants that need to be controlled (not just mercury, but any of 187 hazardous air pollutants, or HAPs) and the level of control that the standards must achieve. The 2005 cap-and-trade rules addressed only mercury, and would have allowed many power plants to avoid control provided they obtained allowances from others who achieved lower pollution levels than required, or reduced emissions sooner than required. The ability of plants to avoid emission control by purchasing allowances could lead to the continuation of "hot spots," areas where mercury concentrations in waterbodies are greater than elsewhere.

By contrast, the statute requires MACT standards applicable at each existing plant to be no less stringent than the average emission limitation achieved by the best performing 12% of existing sources in the industry subcategory.[20] These statutory requirements are referred to as the "MACT floor," because the agency is not allowed to set less stringent standards, nor may it take economic factors into account in determining what the floor will be.

Whether the agency could substitute cap-and-trade rules for the MACT requirements was challenged by the State of New Jersey and others, and, in a 3-0 decision, the D.C. Circuit Court of Appeals vacated the cap-and-trade rules in 2008.[21] The court found that, under Section 112,

[18] The principal route of exposure to mercury is through consumption of fish. Mercury enters water bodies, often through air emissions, and is taken up through the food chain, ultimately affecting humans as a result of fish consumption. All 50 states have issued fish consumption advisories due to mercury pollution, covering 16.8 million acres of lakes, 1.25 million river miles, and the coastal waters of 20 entire states. For a more detailed discussion of mercury's health effects, see CRS Report RL32420, *Mercury in the Environment: Sources and Health Risks*, by Linda-Jo Schierow. For EPA's "2008 Biennial National Listing of Fish Advisories," September 2009, see http://water.epa.gov/scitech/swguidance/fishshellfish/fishadvisories/upload/2009_09_16_fish_advisories_tech2008.pdf.

[19] EPA identified 174 industrial categories to be regulated under the MACT provisions. Standards have been promulgated for almost all these categories except EGUs.

[20] For new sources, the standards are to be based on the emission control achieved by the best controlled similar source.

[21] New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008).

unless EPA "delisted" the category of sources, it had to require that each plant in the category meet MACT standards. Under the statute, delisting would have required a finding that no EGU's emissions exceeded a level adequate to protect public health with an ample margin of safety, and that no adverse environmental effect would result from any source.

Rather than appeal the court's ruling to the Supreme Court or attempt to delist the category, EPA proposed what is referred to as the "Utility MACT," March 16, 2011.[22] The proposal appeared in the *Federal Register* May 3, beginning a public comment period that runs through August 4. Under a consent agreement, the final MACT standards are to be promulgated by November 16, 2011.

The Proposed Rule

As proposed, the Utility MACT would require coal-fired power plants to achieve a 91% reduction from uncontrolled emissions of mercury, nine other toxic metals, and three acid gases, all of which were listed by Congress as hazardous air pollutants in the 1990 Clean Air Act Amendments. Power plants are the largest emitters of many of these pollutants, accounting for about 50% of the nation's mercury emissions, 62% of arsenic emissions, and 82% of hydrochloric acid emissions, for example.[23] The Utility MACT would also reduce emissions of fine particulates ($PM_{2.5}$), which, although not categorized as hazardous air pollutants, are estimated to cause thousands of premature deaths annually.

In proposing the standards, EPA noted that while the requirements are stringent for those facilities lacking controls, 56% of existing coal-fired power plants already are in compliance. Thus, the standards are expected to level the playing field, bringing older, poorly controlled plants up to the standards being achieved by a majority of the existing units. In this respect, the proposed standards reflect the statute's requirement that existing sources of HAPs should meet standards based on the current emissions of the best performing similar sources.

The agency also concluded that some plants, representing less than 10 GW of coal-fired capacity, will be retired by 2015, rather than invest in control technologies. In all, it said, coal-fired generation will decline about 2% compared to estimated generation in the absence of the rule.[24]

Costs, Benefits, and Control Technology

EPA projected the annualized cost of compliance with the proposed rule at $10.9 billion in 2015, and remaining at $10 billion - 11 billion annually through 2030.[25] The average consumer would see an increase of $3-$4 per month in the cost of electricity due to the rule, according to the agency.[26] These costs will go largely to the installation of scrubbers and fabric filters. As a result

[22] For a link to the proposed rule as well as explanatory material, see U.S. EPA, "Reducing Toxic Air Emissions from Power Plants," at http://www.epa.gov/airquality/powerplanttoxics/actions.html.

[23] See U.S. EPA, "Emissions Overview: Hazardous Air Pollutants in Support of the Proposed Toxics Rule," Memorandum from Madeleine Strum, Emission Inventory and Analysis Group, to Marc Houyoux, Group Leader, Emission Inventory and Analysis Group, March 15, 2011, Tables 3 and 4.

[24] U.S. EPA, *Regulatory Impact Analysis of the Proposed Toxics Rule: Final Report*, March 2011, p. 8-17 at http://www.epa.gov/ttn/ecas/regdata/RIAs/ToxicsRuleRIA.pdf. Hereafter, "Utility MACT RIA."

[25] Utility MACT RIA, p. 8-12.

[26] U.S. EPA, "Power Plant Mercury and Air Toxics Standards: Overview of Proposed Rule and Impacts," p. 3, at (continued...)

of the rule, 26 GW of coal-fired units, about 9% of total coal-fired capacity, are expected to install scrubbers. (EPA estimated that by the time the rule requires compliance, 203 GW will already have installed scrubbers anyway, as a result of other regulations.)[27]

More than half of the coal-fired EGU capacity (166 GW) are expected to add fabric filters because of the rule, while 77 GW would have them whether or not there were a rule. In most cases, the fabric filters will be coupled with activated carbon injection or dry sorbent injection.[28] Mercury and other HAPs become attached to the carbon or sorbent after it is injected into the flue gas, and the fabric filter collects the particles, removing them from the plant's emissions. EPA estimates that 62 GW of coal-fired capacity (about one-fifth of the U.S. total) would have either activated carbon or dry sorbent injection in 2015 without the rule. The rule adds another 149 GW of carbon/sorbent installations.

This is not complicated or new technology. Other types of facilities (notably solid waste incinerators) have used this technology for the past 15 years to reduce their mercury and other HAP emissions by 95% or more. As a result of state-level pollution control regulations, a growing percentage of coal-fired power plants do the same.

The benefits of the rule are estimated by EPA at $59 billion to $140 billion annually—5 to 13 times as great as the costs—due primarily to the avoidance of 6,800 to 17,000 premature deaths each year.[29] Other benefits, only some of which were given dollar values, include the annual avoidance of 11,000 nonfatal heart attacks, 120,000 cases of aggravated asthma, and developmental effects on children, including effects on IQ, learning, and memory.[30]

Of the proposed EPA rules, the Utility MACT is probably the most costly and most likely to affect older coal-fired plants that have not yet installed current pollution control technology. EPA's proposal does allow averaging of emissions from multiple units at a single location, which may allow some older units that are operated infrequently to remain in service, but the absence of broader allowance trading provisions in the law and the stringency of the emission requirements mean that most units will not be able to escape regulation.

EEI's and NERC's Analyses of the Utility MACT Rule

In its report, which was written before EPA's Utility MACT proposal, EEI concluded that, "All coal units [would be] required to install a scrubber (wet or dry), activated carbon injection (ACI) and a baghouse/fabric filter" for compliance with the MACT.[31] This goes well beyond what EPA proposed. Compared to EPA's projections, it concluded that five times as much scrubber capacity, nearly three times as much ACI, and about one and one-half times as much baghouse capacity

(...continued)
http://www.epa.gov/airquality/powerplanttoxics/pdfs/overviewfactsheet.pdf.

[27] U.S. EPA, "Reducing Toxic Pollution from Power Plants: EPA's Proposed Mercury and Air Toxics Standards," Overview Presentation, March 16, 2010, p. 15, http://www.epa.gov/airquality/powerplanttoxics/pdfs/presentation.pdf.

[28] Ibid.

[29] Ibid., p. 13.

[30] U.S. EPA, "Fact Sheet: Proposed Mercury and Air Toxics Standards," March 2011, p. 3, at http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf. For additional information, see Utility MACT RIA, pp. 1-2 to 1-10, and Chapter 5.

[31] EEI report, p. 43.

would need to be added, making the rule substantially more costly and far more difficult to comply with in the limited time provided by the statute.

NERC's report, which was also written before EPA proposed the Utility MACT, also assumed that vastly more pollution control equipment would need to be added to coal-fired plants than EPA believes will be necessary. The NERC analysis assumed wet scrubbers would be added to all coal-fired plants that don't already have them, that selective catalytic reduction (SCR) will be added to all bituminous coal-powered facilities, and that activated carbon injection and baghouses would be added at all facilities burning other types of coal.[32] These assumptions are similar to EEI's except that by assuming wet scrubbers (instead of EPA's general assumption that dry scrubbers will suffice) and by assuming SCR at bituminous facilities, the cost impacts would most likely be even greater than the costs in EEI's assessment.[33] NERC concluded that 8.4 GW to 17.6 GW of capacity would be retired or derated as a result of the MACT rule. If fewer units need controls and less expensive pollution control equipment is needed on those that do, the retirements and deratings would be fewer.

Following promulgation of these standards, existing power plants will have three years, with a possible one-year extension, to meet the standards. (The three-to-four-year timeframe is mandated by the statute.) Many in industry argue that three or four years is not enough time to complete the required pollution control equipment installation, and as a result that the reliability of the nation's electric power supply could be affected by the rule. NERC did not say this directly, in part because its analysis combines the effects of four rules, making it difficult to disaggregate the Utility MACT's effect. What it did say was:

> The MACT Rule considered alone could drive Planning Reserve Margins of 8 regions/subregions below the NERC Reference Margin Levels standards and trigger the retirement of 2-15 GW ... of existing coal capacity by 2015. To comply, owners of the remaining capacity need to retrofit from 277 to 753 units with added environmental controls. The "hard stop" 2015 compliance deadline proposed by the MACT Rule makes retrofit timing a significant issue and potentially problematic.[34]

In part, whether or not there is sufficient time to implement the rule without threatening electric system reliability will depend on the number of units that require retrofits. EPA is the only one of the three sources discussed herein that analyzed the actual proposal. Both EEI and NERC assumed requirements that appear to be substantially more stringent than what EPA proposed. If EPA is correct in its analysis, the number of retrofits appears to be within the range of what the industry has accomplished in the past as a result of earlier regulations. This point is discussed below in more detail, under "Train Wreck?"

New Source Performance Standards for Greenhouse Gas Emissions

On December 23, 2010, EPA released the text of a settlement agreement with 11 states, two municipalities, and three environmental groups, under which it agreed to propose New Source Performance Standards (NSPS) to address greenhouse gas emissions from power plants by July 26, 2011, and take final action on the proposal by May 26, 2012. (The agency recently announced

[32] NERC report, p. 50.

[33] For a detailed comparison of equipment cost, see EEI report, p. 33.

[34] NERC report, p. V.

that it will delay proposal until September 30, 2011, but it expects to retain the May 26, 2012 date for final action.) Electric generating units are the largest U.S. source of greenhouse gas (GHG) emissions, accounting for about one-third of total U.S. emissions. Coal-fired plants accounted for 81% of the electric power industry's total GHG emissions in 2009[35] and, thus, are expected to be the main focus of EPA's NSPS rules.

New Source Performance Standards are emission limitations imposed on designated categories of major new (including substantially modified) stationary sources of air pollution. CAA Section 111 gives EPA authority to set NSPS for emissions of "air pollutants," a term that includes greenhouse gases.[36] A new source is subject to NSPS regardless of its location (i.e., the same standards apply to all new and modified major facilities anywhere in the United States). The statute provides authority for EPA to impose such standards directly in the case of new (or modified) sources (Section 111(b)), and through the states in the case of existing sources (Section 111(d)). The authority to impose performance standards on new and modified sources refers to any category of sources that the EPA Administrator judges "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare" (Sec. 111(b)(1)(A))—language similar to the endangerment and cause-or-contribute findings EPA used to promulgate GHG emission standards for motor vehicles in 2010.

In establishing these standards, Section 111 gives EPA considerable flexibility with respect to the source categories regulated, the size of the sources regulated, and the particular gases regulated, along with the timing and phasing in of regulations. This flexibility extends to the stringency of the regulations with respect to costs and secondary effects, such as non-air-quality, health and environmental impacts, along with energy requirements. This flexibility is encompassed within the Administrator's authority to determine the control systems that have been "adequately demonstrated." Standards of performance developed by the states for existing sources under Section 111(d) can be similarly flexible.

Assuming EPA promulgates the greenhouse gas NSPS on schedule, how quickly such standards would be applied to existing sources is an open question. EPA must first propose and promulgate guidelines, following which the states would be given time to develop implementation plans.[37] Following approval of the plans, the act envisions case-by-case determinations of emission limits, in which the states may consider, among other factors, the remaining useful life of a source in setting an emission limit. Thus, it is likely to be several years before existing power plants are subject to emission limits for GHGs.

Since EPA has not yet proposed NSPS, the agency has not provided a Regulatory Impact Analysis or cost estimate for such a rule.[38] EEI, on the other hand, in six of the nine scenarios in its

[35] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, Table 2-13, available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

[36] In Massachusetts v. EPA (549 U.S. 497 (2007)), the Supreme Court held, in a 5-4 decision, that greenhouse gases are clearly air pollutants under the Clean Air Act's definition of that term.

[37] How much time the states would be given to submit plans is unclear. The statute says that the regulations shall establish a procedure "similar to that" provided for State Implementation Plans under Section 110, which generally give states three years to submit a plan, following which EPA reviews it to determine its adequacy.

[38] Agency guidance for state GHG permitting decisions, issued in November 2010, is perhaps the best example of what the agency might require: the guidance focuses on energy efficiency as the best available control technology, and states that both conversion to natural gas and carbon capture and sequestration can be eliminated from consideration. While cost is not estimated in the guidance, the requirements would not appear to be stringent. For a discussion of EPA's guidance, see CRS Report R41505, *EPA's BACT Guidance for Greenhouse Gases from Stationary Sources*, by Larry (continued...)

analysis, assumed there would be CO_2 regulations in place by 2017. In five of the scenarios, it estimated the cost of CO_2 regulation or legislation at $25 per ton of emissions in 2017, with price escalation of 5% annually thereafter. This assumption would impose a larger burden on coal-fired power plants than any of the other rules considered in EEI's report. In 2009, coal-fired electric power plants emitted 1,748 million tons of CO_2.[39] Assuming roughly the same level of emissions in 2017, EEI's $25/ton assumption would result in a cost of CO_2 regulation of $43.7 billion in 2017, with 5% increases each year thereafter. This cost, which appears to have been based on its analysis of legislation not enacted in the 111th Congress, dwarfs every other projected regulatory cost in the regulatory impact analyses that CRS examined. Inclusion of this requirement leads, in EEI's analysis, to an additional 23 GW of retired capacity in 2015 and 40 GW of incremental retirements in 2020, accounting for more than half of all retirements in the latter year.[40]

NERC, on the other hand, did not include CO_2 regulation in its study.

NAAQS Revisions

EPA is required in CAA Sections 108 and 109 to set National Ambient Air Quality Standards (NAAQS) for air pollutants that endanger public health ("primary" NAAQS) or welfare ("secondary" NAAQS) and that are emitted by numerous or diverse sources. NAAQS do not directly regulate emissions. Rather, the primary NAAQS identify pollutant concentrations in ambient air that must be attained to protect public health with an adequate margin of safety. Secondary NAAQS identify concentrations necessary to protect public welfare, a broad term that includes damage to crops, vegetation, property, building materials, and more.

In essence, NAAQS are standards that define what EPA considers to be clean air. Their importance stems from the long and complicated implementation process that is set in motion by their establishment. Once NAAQS have been set, EPA, using monitoring data and other information submitted by the states to identify areas that exceed the standards and must, therefore, reduce pollutant concentrations to achieve them. State and local governments then have three years to produce State Implementation Plans which outline the measures they will implement to reduce the pollution levels in these "nonattainment" areas. Nonattainment areas are given anywhere from three to 20 years to attain the standards, depending on the pollutant and the severity of the area's pollution problem.

EPA also acts to control many of the NAAQS pollutants wherever they are emitted through national standards for certain products that emit them (particularly mobile sources, such as automobiles) and emission standards for new stationary sources, such as power plants.

In the 1970s, EPA identified six pollutants or groups of pollutants for which it set NAAQS.[41] But that was not the end of the process. When it gave EPA the authority to establish NAAQS, Congress anticipated that the understanding of air pollution's effects on public health and welfare

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Parker and James E. McCarthy.

[39] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, Table 2-13, available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

[40] EEI report, p. v.

[41] The six pollutants are ozone, particulates, carbon monoxide, SO_2, NOx, and lead.

would change with time, and it required that EPA review the standards at five-year intervals and revise them, as appropriate.

The agency is currently conducting the required reviews of these standards: it has already completed reviews for five of the six standards, but two of them have been remanded by the D.C. Circuit Court of Appeals for further agency action, and others are being challenged in court. The electric power industry and others are following this process closely, because more stringent standards could begin a process that would lead to more stringent emission standards.[42]

The three standards most likely to affect power plants are those for SO_2, ozone, and particulate matter (PM).

Sulfur Dioxide (SO_2)

On June 22, 2010, EPA revised the NAAQS for SO_2, focusing on short-term (1-hour) exposures. The prior standards (for 24-hour and annual concentrations), which were set in 1971, were revoked as part of the revision. Since 1971, EPA had conducted three reviews of the SO_2 standard without changing it. However, following the last of these reviews, in 1998, the D.C. Circuit Court of Appeals remanded the SO_2 standard to EPA, finding that the agency had failed adequately to explain its conclusion that no public health threat existed from short-term exposures to SO_2.[43] Twelve years later, EPA revised the standard to respond to the court's decision.

The new short-term standard is substantially more stringent than the previous standards: it replaces a 24-hour standard of 140 parts per billion (ppb) with a 1-hour maximum of 75 ppb. This means that there could be an increase in the number of SO_2 nonattainment areas (especially since there were *no* nonattainment areas under the old standards), with additional controls required on the sources of SO_2 emissions in any newly designated areas. Since electric generating units accounted for 60% of total U.S. emissions of SO_2 in 2009, additional controls on EGUs would be likely.

The timing and extent of any additional controls is uncertain, however, for several reasons. First, the monitoring network needed to determine attainment status is incomplete and is not primarily configured to monitor locations of maximum short-term SO_2 concentrations.[44] The agency says it will need 41 new monitoring sites to supplement the existing network in order to have a more complete data base. Since three years of data must be collected after a site's startup to determine attainment status, it may be as late as 2016 before some areas will have sufficient data to be classified. Even if the areas can be designated sooner based on modeling data, it would be at least 2015 before State Implementation Plans with specific control measures would be due, and actual compliance with control requirements would occur several years later.

Meanwhile, SO_2 emissions will be significantly reduced as a result of the CAIR, Cross-State, and Utility MACT rules described above. Thus, although EPA identified 59 counties that would have

[42] Five of the entries on EEI's "train wreck" chart (**Figure 1**) refer to NAAQS reviews.

[43] American Lung Association v. EPA, 134 F.3d 388 (D.C. Cir 1998).

[44] U.S. EPA, "Fact Sheet: Revisions to the Primary National Ambient Air Quality Standard Monitoring Network, and Data Reporting Requirements for Sulfur Dioxide," June 2, 2010, p. 3, at http://www.epa.gov/air/sulfurdioxide/pdfs/20100602fs.pdf.

violated the new SO_2 NAAQS based on 2007-2009 data, it is not clear whether any of these counties will be in nonattainment by the time EPA designates the nonattainment areas.

In its Regulatory Impact Analysis of the SO_2 NAAQS, the agency estimated that attainment would require a reduction of 370,000 tons of SO_2 by 2020, about two-thirds of which would need to come from EGUs.[45] The agency estimated the annualized cost of these controls (for all sources, not just EGUs) at $1.5 billion. Benefits would range from $15 billion to $37 billion annually.[46]

These costs and benefits do not take account of CAIR, the Cross-State Rule, or the Utility MACT, however. (As may be recalled, the CAIR and Cross-State Rules will result in more than 6 million tons of SO_2 emission reductions by 2014.) The agency assumed for purposes of analysis that none of these rules was in effect, because none of them was in effect in 2005, the base year used for analytical purposes. As the agency's RIA states:

> The baseline for this analysis is complicated by the expected issuance of additional air quality regulations. The SO_2 NAAQS is only one of several regulatory programs that are likely to affect EGU emissions nationally in the next several years. We thus expect that EGUs will apply controls in the coming years in response to multiple rules. These include the maximum achievable control technology (MACT) rule for utility boilers, revisions to the Clean Air Interstate Rule, and reconsideration of the Clean Air Mercury Rule. Therefore controls and costs attributed solely to the SO_2 NAAQS in this analysis will likely be needed for compliance with other future rules as well.[47]

In short, compared to the Utility MACT and the Cross-State Rule, the SO_2 NAAQS has relatively little impact on coal-fired power plants in EPA's analysis, and the agency's analysis relied on assumptions that probably overstate the impact of the standard.

EEI included the SO_2 NAAQS on its "train wreck" timeline, but neither EEI nor NERC considered the standard in their analyses.

Ozone

On January 19, 2010, EPA proposed a revision of the NAAQS for ozone.[48] EPA currently expects to finalize this revision by the end of July 2011 (although it has already postponed the review's completion date three times). As noted above, NAAQS do not directly limit emissions, but they set in motion a process under which "nonattainment areas" are identified and states and EPA develop plans and regulations to reduce pollution in those areas.

Ozone is not directly emitted by coal-fired power plants (or most other sources). It forms in the atmosphere as the result of a chemical reaction between nitrogen oxides (NOx), volatile organic compounds (VOCs), and carbon monoxide (CO) in the presence of sunlight. Power plants emit

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[45] U.S. EPA, Office of Air Quality Planning and Standards, *Final Regulatory Impact Analysis (RIA) for the SO2 National Ambient Air Quality Standards (NAAQS)*, June 2010, page ES-7, Table ES.2, at http://www.epa.gov/ttnecas1/regdata/RIAs/fso2ria100602full.pdf.

[46] Ibid., p. ES-9, Table ES.4.

[47] Ibid., p. ES-3.

[48] U.S. Environmental Protection Agency, "National Ambient Air Quality Standards for Ozone; Proposed Rule," 75 *Federal Register* 2938, January 19, 2010.

one of these precursor emissions, NOx. Thus, the setting of a more stringent ozone standard might lead to tighter controls on their NOx emissions.

The ozone standard affects a large percentage of the population: as of September 2010, 119 million people (nearly 40% of the U.S. population) lived in areas classified "nonattainment" for the current ozone standard. The proposed revision would lower the primary (health-based) standard from 0.075 parts per million—75 parts per billion (ppb)—averaged over 8 hours to somewhere in the range of 70 to 60 ppb averaged over the same time.

EPA has identified at least 515 counties that would violate the proposed ozone NAAQS if the most recent three years of data available at the time of proposal were used to determine attainment (compared to 85 counties that violated the standard in effect at that time). The proposal would also, for the first time, set a separate standard for public welfare, the principal effect of which would be to call attention to the damage by ozone to forests and agricultural productivity.

As with other NAAQS, the standards, when finalized, would set in motion a long implementation process that has far-reaching impacts. The first step, designation of nonattainment areas, is expected to take place within a year of the new standards' promulgation; the areas so designated would then have 3 to 20 years to reach attainment.

EPA is prohibited by the statute from considering costs in setting NAAQS, but it does prepare cost and benefit estimates for information purposes. The agency estimated that the costs of implementing the revised ozone NAAQS (for all sources of ozone precursors) would range from $19 billion to $25 billion annually in 2020 if the standard chosen is 70 ppb, or $52 billion to $90 billion if the standard chosen is 60 ppb,[49] with benefits of roughly the same amount.

Although the ozone NAAQS revision is one of the most expensive EPA rules under development, it is unlikely to have major impacts on electric generating units. Fuel combustion by electric utilities accounted for 13% of NOx emissions nationally in 2009, and less than 1% of VOC and CO emissions. Thus, other sources account for most of the emissions and are likely to be the main focus of the emission controls necessary to reach attainment of the standard. Furthermore, to the extent that utility NOx emissions are targeted, it will likely be through the Cross-State Rule, or a successor to it, whose impacts were discussed above. The ozone NAAQS would primarily serve as a driver in the development of these other rules.

As with the SO_2 NAAQS, EEI included the ozone NAAQS on its "train wreck" diagram, but neither EEI nor NERC considered the standard in their analyses.

Particulate Matter

A third NAAQS whose revision could affect coal-fired power plants is that for particulate matter (PM). The PM NAAQS, which includes standards for both coarse and fine particulates (PM_{10} and $PM_{2.5}$, respectively), was last revised in October 2006. The D.C. Circuit Court of Appeals remanded the $PM_{2.5}$ standards to EPA in February 2009,[50] so EPA is both conducting the statutory

[49] U.S. EPA, "Fact Sheet: Supplement to the Regulatory Impact Analysis for Ozone," January 7, 2010, at http://www.epa.gov/air/ozonepollution/pdfs/fs20100106ria.pdf.

[50] American Farm Bureau Fed'n v. EPA, 559 F.3d 512 (D.C. Cir. 2009).

five-year review of the standard and responding to the D.C. Circuit decision. The agency expects to propose revised standards for both $PM_{2.5}$ and PM_{10} by summer 2011, with promulgation perhaps taking place in 2012.

EPA staff have recommended a strengthening of the PM NAAQS,[51] but at this time, there is no proposal to be evaluated. Fuel combustion by electric utilities is the source of 8.3% of $PM_{2.5}$ and 3.5% of PM_{10}.

As with the other NAAQS, EEI included the PM NAAQS on its "train wreck" diagram, but neither EEI nor NERC considered the standard in their analyses.

Revised Cooling Water Intake Rule

Power plants withdraw large volumes of water for production and, especially, to absorb heat from their industrial processes. Water withdrawals by electric generating plants, used primarily for cooling, are the largest water use category by sector in the United States—201 billion gallons per day (BGD) in 2005. Although water withdrawal is a necessity for these facilities, it also presents special problems for aquatic resources. Cooling water intake structures (CWIS) can cause two types of environmental harm. First, impingement occurs when fish, invertebrates, and other aquatic life are trapped on equipment on intake screens at the entrance to the CWIS. Second, entrainment occurs when small organisms pass through the intake screening system, travel through the cooling system pumps and tubes, and then are discharged back into the source water. Impingement and entrainment injure or kill large numbers of aquatic organisms at all life stages. Section 316(b) of the Clean Water Act (CWA) authorizes regulation of CWIS to protect such organisms from being harmed or killed.

Regulatory efforts by EPA to implement Section 316(b) have a complicated history over 35 years, including legal challenges at every step by industry groups and environmental advocates. Currently most new facilities are regulated under rules issued in 2001, while rules for existing facilities issued in 2004 were challenged and remanded to EPA for revisions. In response to the remand, in March 2011 EPA proposed national requirements expected to affect 559 existing electric generators; 483 are fossil-fuel facilities. The affected facilities comprise approximately 11% of the steam electric generating facilities and over 45% of the electric power sector capacity in the United States. Publication of the CWIS proposal in the *Federal Register* on April 20 triggered a 90-day public comment period that ends on August 18, 2011.[52] EPA is under a court-ordered schedule to issue a final CWIS rule by July 27, 2012.

Even before release, the proposed regulations were highly controversial among stakeholders and some Members of Congress who questioned whether a stringent and costly environmental mandate could jeopardize reliability of U.S. electricity supply. Many in industry feared, while

[51] On July 2, 2010, EPA released the *Second External Review Draft of its Policy Assessment for the Review of the Particulate Matter NAAQS*. The draft represented EPA staff's recommendations to the Administrator. It outlined options for revising both the fine and coarse particulate standard, both of which would make the standards more stringent. The draft is available at http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_2007_pa.html.

[52] U.S. Environmental Protection Agency, "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities," 76 *Federal Register* 22174-22228, April 20, 2011. On July 20, EPA published a notice providing for 30 additional days of public comment beyond the time originally scheduled, to August 18, 2011. For information, see CRS Report R41786, *Cooling Water Intake Structures: Summary of EPA's Proposed Rule*, by Claudia Copeland.

environmental groups hoped, that EPA would require installation of technology called closed-cycle cooling that most effectively minimizes the environmental damage of CWIS, but also is the most costly technology option.

In its proposed rule, EPA evaluated four regulatory options expected to minimize the harm to aquatic species of CWIS at existing facilities, each with varying environmental benefits and costs.[53] The agency concluded that closed-cycle cooling reduces CWIS impacts to a greater extent than other technologies, but declined to mandate closed-cycle cooling universally and instead favored a less costly, more flexible regulatory option. EPA's recommended approach would essentially codify current CWIS permitting procedures for existing facilities, which are based on site-specific determinations and have been in place administratively for some time because of legal challenges to previous rules. The agency based the conclusion to not mandate closed-cycle cooling on four factors: additional energy needed by electricity and manufacturing facilities to operate cooling equipment, and threats to reliability of energy delivery (i.e., energy penalty); additional air pollutants that would be emitted because fossil-fueled facilities would need to burn more fuel as compensation for the energy penalty; land availability concerns in some locations; and limited remaining useful life of some facilities such that retrofit costs would not be justified. EPA estimates that more than 90 of the 559 affected electric generators already have the technology required to demonstrate compliance with the proposed rule.

Compliance with the rule, when promulgated in 2012, will be required as soon as possible. For individual facilities, specific compliance deadlines will be set when the facility next seeks to renew its existing CWA discharge permit; such permits are issued for five-year periods and then must be reissued by the permitting authority (state or EPA). Permitting agencies often allow facilities some time to come into compliance with new requirements. As proposed by EPA, for facilities already in compliance with the rule or needing to install technologies other than cooling towers, the compliance period is assumed to be a five-year period from 2013 to 2017. EPA expects that facilities required to install cooling towers for entrainment mortality control will require a longer period of time. Fossil-fuel electric power generating facilities would achieve compliance from 2018 to 2022.[54] EPA estimated that the annual costs of the proposed rule will be $319 million, while benefits will be $17.6 million annually.[55] EPA also estimated that a net nine generating units would be retired as a result of the rule.[56] EPA did not identify potential retirements by fuel source.

Industry groups generally view the March 2011 proposal favorably (at least in comparison with what had been anticipated), although they favor still more flexibility, while environmental advocates are critical that the proposal does not mandate stricter technological options to provide

[53] Three of the regulatory options considered by EPA would require all existing electric generators covered by the rule to use screens to prevent impingement of fish, but they differ with respect to requiring closed-cycle cooling towers to prevent entrainment. The fourth option would allow permitting authorities to establish impingement and entrainment controls on a case-by-case basis for small and medium EGUs and would require uniform controls for larger facilities. The agency's preferred option would require uniform impingement standards (i.e., screens) for all power plants and case-by-case determination of need for cooling towers for all facilities.

[54] EPA believes that permitting authorities would need to coordinate outages by multiple power generating facilities in a geographic area so as to minimize impacts on reliability of power generation. In these circumstances, EPA expects a facility could reasonably require as long as eight years to attain compliance.

[55] Costs and benefits are annualized over 50 years and discounted at a 3% rate.

[56] EPA concluded that 39 EGUs would be retired, but that 30 others would avoid closure because of EPA's recommendation of a rule that does not mandate cooling tower retrofits.

greater protection of aquatic resources. States will be responsible for most permitting actions to implement the rule. Since many states are coping with constrained budgets, some of them favor a regulatory approach that requires them to make fewer case-by-case decisions, thus imposing less administrative cost.

Prior to release of the EPA proposal, industry assumed that the agency would propose a more stringent rule with a more rapid timeline for compliance. Both EEI and NERC assumed that EPA would mandate that existing power plants retrofit by installing closed-cycle cooling systems. EEI assumed that the CWIS rule would affect 314 GW of capacity and a total of 400 electric generating units, at a cost of $16 billion through 2020. EEI did not estimate or separate out how many plant retirements would result from the anticipated CWIS rule.

The NERC analysis assumed that mandatory cooling tower retrofits would be required by 2018, and on that basis, NERC concluded that the CWIS rule would be the most costly of the four EPA rules that it examined (although NERC did not estimate compliance costs for this rule), with the greatest likely impact on electricity capacity. NERC concluded that such a rule would lead to power plant retirements totaling 33 GW of capacity. However, NERC also concluded that only 2.5 GW of that total would be coal-fired power plants (representing 94 coal steam units). According to NERC, the largest impact of such a CWIS rule would be on older oil- and gas-fired units, with 253 units totaling 30 GW of capacity expected to be economically vulnerable and thus likely to be retired.[57]

Revised Steam Electric Effluent Guidelines

Under authority of CWA Section 304, EPA establishes national technology-based regulations, called effluent limitation guidelines (ELGs), to reduce pollutant discharges from industries directly to waters of the United States and indirectly to municipal wastewater treatment plants. EPA has issued ELGs for 56 industries that include many types of dischargers, such as manufacturing and service industries. These requirements are incorporated into discharge permits issued by EPA and states. The current steam electric power plant rules,[58] which were promulgated in 1982, apply to about 1,200 nuclear- and fossil-fueled steam electric power plants nationwide, 500 of which are coal-fired.

In a 2009 study,[59] EPA found that the current regulations do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades, specifically the increase of flue gas desulfurization (FGD) systems, or scrubbers, at coal-fired power plants to control air pollution. According to EPA, as of June 2008, 30% of coal-fired power plants were using FGD systems to control SO_2 emissions from the flue gas generated in the plants' boilers and prevent buildup of certain corrosive constituents such as chlorides, and by 2025, nearly 80% of coal-fired generating capacity is expected to employ FGD systems. While scrubbers dramatically reduce emissions of harmful pollutants into the air, some create a significant liquid waste stream (especially wet scrubbers). In addition, discharges from coal combustion waste (CCW) ash impoundments at steam electric

[57] NERC report, pp. 14-15.

[58] 40 CFR § 423.10.

[59] U.S. Environmental Protection Agency, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report*, EPA 821-R-09-008, October 2009.

power plants have a potential to degrade water quality. Concern about releases of CCW grew following the collapse of ash impoundment dams at Tennessee Valley Authority (TVA) power plants, discussed further under "Coal Combustion Wastes," below. Pollutants of concern associated with FGD systems and CCW include a large number of metals (e.g., mercury, arsenic, chromium, and selenium), chloride, nitrogen compounds, and total dissolved and suspended solids. EPA believes that many current CWA permits for power plants do not fully address potential water quality impacts of these discharges through appropriate pollutant limits and monitoring and reporting requirements.

Under the CWA , EPA has a duty to review existing ELGs at least every five years and, if appropriate, revise them. EPA had been studying the effluent limitations for the steam electric power generating category since the mid-1990s and on several occasions indicated that a preliminary study of discharges from this category was necessary. In 2009, environmental groups sued EPA to compel the agency to commit to a schedule for issuing revised guidelines. Pursuant to a November 8, 2010 consent decree that it entered into with environmental litigants, EPA agreed to propose the revised power plant ELG by July 23, 2012, and to finalize the rule by January 31, 2014. The rulemaking will address wastewater discharges from CCW ash storage ponds and FGD air pollution controls, as well as other power plant waste streams.[60] As with the CWIS rule discussed above, compliance with specific regulations, which cannot be anticipated at this time, will occur over several years with full compliance likely not required before 2019 or 2020.

Until EPA proposes a regulation, the substance, cost, and impact of a rule are speculative. Still, even before EPA proposes a new ELG for power plants, the agency has launched an effort to scrutinize state-issued CWA discharge permits for power plants as an interim measure to address longstanding concerns that the permits need to be strengthened. In a June 2010 letter to environmental groups, EPA committed to reviewing at least 35 CWA permits for power plants before the end of 2012 and simultaneously provided EPA regional offices with interim guidance to assist state and EPA permitting authorities to establish appropriate requirements for power plant wastewater discharges.[61]

Since EPA has not proposed a revised steam electric power ELG rule, the agency has not provided a Regulatory Impact Analysis or cost estimate for such a rule. EEI included an ELG rule in the timeline shown in **Figure 1**, but did not analyze or project what a rule would look like, or what its impact might be. NERC did not include an ELG rule in its analysis.

Coal Combustion Waste[62]

Coal combustion waste (CCW) is inorganic material that remains after pulverized coal is burned for electricity production.[63] A tremendous amount of the material is generated each year—

[60] Separately, EPA also is considering regulation of coal ash disposal sites under Resource Conservation and Recovery Act, as discussed in this report under "Coal Combustion Waste."

[61] James A. Hanlon, Director, EPA Office of Wastewater Management, "National Pollutant Discharge Elimination System (NDES) Permitting of Wastewater Discharges from Flue Gas Desulfurization (FGD) and Coal Combustion Residuals (CCR) Impoundments at Steam Electric Power Plants," memorandum, June 7, 2010, on file with authors.

[62] This section of the report was written by Linda Luther, Analyst in Environmental Policy.

[63] In its June 2010 regulatory proposal, EPA refers to the material as coal combustion *residuals*. It is also commonly referred to as coal combustion *byproducts* or *materials*. How the material is referred to generally depends on the (continued...)

industry estimates that as much as 135 million tons were generated in 2009, making it one of the largest waste streams generated in the United States. Disposal of CCW onsite at individual power plants may involve decades-long accumulation of tons of dry ash (in a landfill) or wet ash slurry (in a surface impoundment) deposited at the site.

On December 22, 2008, national attention was turned to risks associated with managing such large volumes of waste when a breach in a surface impoundment pond at TVA's Kingston, TN, plant released 1.1 billion gallons of coal fly ash slurry that damaged or destroyed homes and property. Beyond the potential for a sudden, catastrophic release from a surface impoundment, a more common threat associated with CCW management is the leaching of contaminants likely present in the waste, primarily heavy metals, resulting in surface or groundwater contamination. This risk is particularly high at unlined surface impoundments which are likely in common use today.

The Kingston release also brought attention to how the waste is managed and regulated. CCW management is largely exempt from federal regulations and is regulated by individual states. State requirements generally apply to two broad categories of CCW management—its *disposal* in landfills, surface impoundment, or mines, and its *beneficial use* (e.g., as a component in concrete, cement, or gypsum wallboard, or as structural or embankment fill). Inconsistencies and deficiencies in state regulatory programs have been identified by EPA as one reason that national standards to regulate CCW are needed. More recently, EPA called into question the effectiveness of some state regulatory programs for protecting human health and the environment.

As discussed below, to establish a national standard necessary to address potential threats of improper management of CCW to human health and the environment, on June 21, 2010, EPA proposed two regulatory options.[64]

Regulatory Background

The evolution of CCW regulation began in 1978 when EPA first proposed hazardous waste management regulations under Subtitle C of the Resource Conservation and Recovery Act (RCRA).[65] However, in 1980, Congress amended the law to exclude CCW from regulation under Subtitle C, pending EPA's completion of a report to Congress and regulatory determination on whether hazardous waste regulations were warranted.[66] In response, EPA published regulatory determinations in 1993 and 2000 retaining that exemption, concluding on both occasions that CCW did not warrant regulation as hazardous waste. However, in the 2000 determination EPA stated that national regulations under Subtitle D (applicable to non-hazardous solid waste) were

(...continued)

context in which it is being discussed. For example, coal combustion *waste* is generally destined for disposal, while coal combustion *byproducts* or *residuals* may be destined for some use such as a component in gypsum wallboard or cement. Regardless of what it is called, these terms refer to the same substances. Since EPA's regulatory proposal primarily discusses issues associated with the materials' disposal, it is referred to here as coal combustion *waste* (CCW).

[64] U.S. EPA, "Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities," 75 *Federal Register* 35127-35264, June 21, 2010.

[65] RCRA actually amends earlier legislation, the Solid Waste Disposal Act of 1965, but the amendments were so comprehensive that the act is commonly referred to as RCRA rather than by its official title.

[66] This exclusion was specified in Solid Waste Disposal Act Amendments of 1980 (P.L. 96-482) at 42 U.S.C. 6921(b)(3)(A)(i). The provisions are commonly referred to as the "Bevill Amendment" or the "Bevill exclusion."

warranted for CCW disposal in landfills and surface impoundments for reasons including new data about potential risks to human health and the environment and concerns about the adequacy of state regulatory programs. EPA stated that it would revise its determination that regulation under Subtitle C was not needed if it found that a need for such regulation was warranted.

After accumulating new data regarding CCW management, in October 2009, EPA developed a draft regulatory proposal to list the material as hazardous waste under Subtitle C of RCRA. Under the draft proposal, EPA would establish land disposal and treatment standards for CCW. EPA cited several reasons for determining that regulation under Subtitle C was needed based on new data which showed that disposal in unlined landfills and surface impoundments presents substantial risks to human health and the environment from releases of toxic constituents, that a large amount of waste is still being disposed in units that lack necessary protections, and state programs have not been sufficiently improved to address gaps that EPA had previously identified.[67]

Current Regulatory Proposal

As a result of review by the Office of Management and Budget, EPA's draft proposal underwent substantial changes. The final proposal, published on June 21, 2010, stated that the determination to revise the regulatory determination had not yet been made. It proposed two regulatory options for consideration. Under the first option, EPA would draw on its existing authority to list a waste as hazardous and to regulate it. The second option would keep the Subtitle C exclusion in place, but would establish national criteria applicable to landfills and surface impoundments under RCRA's Subtitle D non-hazardous solid waste requirements. Under Subtitle D, EPA does not have the authority to implement or enforce its proposed requirements. Instead, EPA would rely on states or citizen suits to enforce the new standards. However, in support of the Subtitle D option, EPA cited industry's concern that labeling CCW as hazardous waste would stigmatize beneficial uses of the material and ultimately increase the amount that must be disposed.[68]

The public comment period for EPA's proposal ended on November 19, 2010. It is unclear when, or if, EPA will ultimately promulgate a final rule. On March 3, 2011, EPA Administrator Lisa Jackson testified that she does not anticipate a final rule to be promulgated in 2011, due to the large number of public comments received.[69]

During several congressional hearings, some Members of Congress also have expressed concern over EPA's ultimate decision to regulate CCW. Their concerns about potential Subtitle C regulations relate primarily to the potential impacts those requirements may ultimately have on coal-producing states, state regulatory agencies, energy prices, and CCW recycling opportunities. On the other hand, concerns expressed by other Members regarding the Subtitle D option generally relate to concerns that human health and the environment would not be sufficiently protected given EPA's lack of authority to enforce Subtitle D requirements.

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[67] For more information about EPA's regulatory proposal, see CRS Report R41341, *EPA's Proposal to Regulate Coal Combustion Waste Disposal: Issues for Congress*, by Linda Luther.

[68] Opponents of the Subtitle D option have argued the opposite point—that recycling may actually increase if disposal becomes more costly under the Subtitle C requirements.

[69] House Committee on Appropriations, Subcommittee on Interior, Environment, and Related Agencies, March 3, 2011, EPA budget hearing.

EPA's Regulatory Impact Analysis (RIA) estimated potential costs and benefits associated with the 2010 regulatory proposal. The RIA estimated average annualized regulatory costs to be approximately $1.5 billion a year under the Subtitle C option and $587 million a year under the Subtitle D option. EPA also estimated annualized "regulatory benefits." Under the Subtitle C option, regulatory benefits would range widely depending on whether there would be increases in recycling due to added costs of disposal, or decreases in recycling due to possible "stigma" effects of regulating the material under Subtitle C.[70] EPA estimated that if a decrease in beneficial use were to occur, this could result in increased costs of $16.7 billion, while induced increases in recycling could result in a regulatory benefit of $7.4 billion a year. Under the Subtitle D option, the regulatory benefit is estimated to range from $85 million to $3 billion a year.[71]

The EEI report estimated that if the Subtitle C option were adopted, costs would be considerably higher than projected by EPA, based largely on two costs that were not considered by EPA—costs of retrofitting existing disposal units to meet new standards, and the costs of sending the waste to an offsite commercial hazardous waste disposal facility. With regard to the first cost, neither of EPA's regulatory options would require existing landfills to be retrofitted to meet new regulatory standards as long as they install groundwater monitoring systems and implement corrective action, as needed, while existing surface impoundments would be required to be retrofitted. However, based on its past experience with surface impoundment regulations, EPA assumed that facilities would choose to close rather than retrofit. EEI assumed that some portion would retrofit. With regard to the second cost, EEI assumes that under potential Subtitle C requirements, siting or zoning restrictions and state or local ordinances would affect a facility's decision to open a new CCW landfill. However, these factors are difficult to evaluate. Electric utilities currently operate CCW landfills on-site; no data have been presented that indicate that future landfills could not meet EPA's proposed location restrictions or design requirements or that additional restrictions would prohibit or limit the potential for on-site disposal. Further, according to industry statements, new CCW landfills are already built with liners and groundwater monitoring systems. Thus, there is little evidence to suggest that new Subtitle C standards would differ greatly from what has, up until now, been common industry practice.

Other Regulatory Actions Affecting Coal Power

EPA and other federal agencies (the Office of Surface Mining and Reclamation, in the Department of the Interior; and the U.S. Army Corps of Engineers) are developing a series of actions and regulatory proposals to reduce the harmful environmental and health impacts of surface coal mining, including a practice called mountaintop removal mining, in Appalachia. These actions would not affect electric power plants directly, and thus are not covered by EEI nor NERC in their studies. Nevertheless, numerous critics have included actions by EPA, the Corps of Engineers, and the Interior Department regarding mountaintop removal mining in Appalachia in what they term a "War on Coal." Some of these EPA-Corps-Interior actions are discussed in **Appendix A** to this report.

[70] Potential benefits to the Subtitle C option also included groundwater protection benefits (e.g., human cancer prevention benefits) and remediation or cleanup costs avoidance after groundwater contamination or surface impoundment breach.

[71] For more detail on cost estimates, see 75 *Federal Register* 35134 and 35211-35220, June 21, 2010.

The Future for Coal-Fired Power

Virtually all the analyses agree that coal will continue to play a substantial role in powering electric generation for decades to come. EPA, for example, in the Utility MACT RIA, concluded that coal-fired generation will be roughly the same in 2015 as it was in 2008, despite the impact of the MACT and other rules.[72] By 2030, the agency projects that 43% of the nation's electricity will still be powered by coal.[73] (The current level is 45%.) EEI projected that coal will be responsible for 36% to 46% of electricity generation in 2020, depending on the scenario.

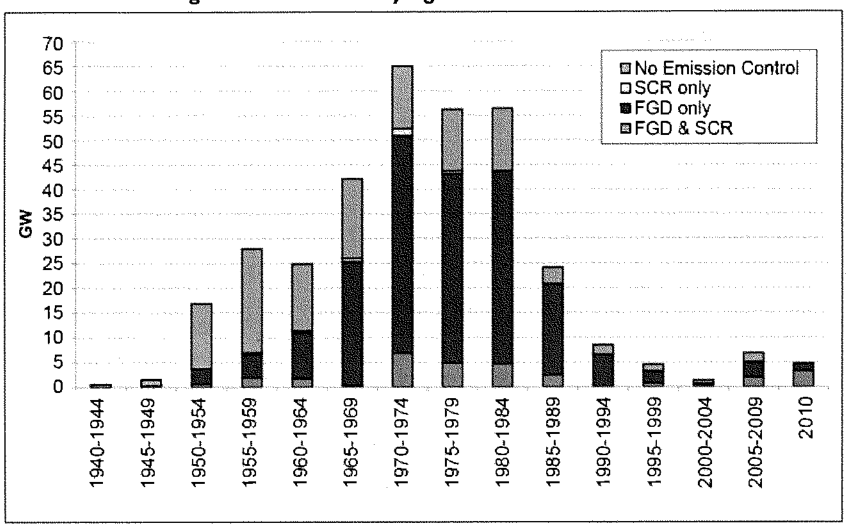
There *will* be retirements of coal-fired capacity, however, as all of the analyses conclude. The number of these retirements, and the role of EPA regulations in causing them, are matters of dispute. The most extreme scenario in EEI's analysis showed 76 GW of coal-fired capacity retirements by 2020 (a little less than 25% of current capacity) as a result of the regulations it analyzed. As noted in the discussion of the individual regulations, in many cases EEI's analysis assumed regulations far more stringent than EPA actually proposed.

The units that would retire are the least economic and/or those currently operating with minimal pollution controls. As noted in **Figure 5**, there are 110 GW of coal-fired plants (about one-third of all coal-fired capacity) that began operating between 1940 and 1969, and two-thirds of these plants do not have scrubbers. These are the prime candidates for retirement.

[72] Utility MACT RIA, p. 8-16; 2008 data are from U.S. DOE, Energy Information Administration, *Electric Power Annual 2009*, April 2011, Table 2.1, available at http://www.eia.gov/cneaf/electricity/epa/epa_sum.html.

[73] Utility MACT RIA, p. 8-16.

Figure 5. Coal Plants by Age and Emission Controls



Source: Sue Tierney, "EPA Proposed Utility Air Toxics Rule –Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, p. 4.

In many cases, these older plants are not base-load plants, so their significance as a percentage of coal-fired generation is less than one might assume from adding up their nominal capacity. In a presentation to congressional staff, Sue Tierney, a former Assistant Secretary of Energy, presented data showing that the pre-1970 units operating without emission controls are in use only 41% of the time.[74]

EPA's modeling confirmed that the plants likely to be retired are older, smaller, and less frequently used: the agency concludes, for example, that under the MACT rule the average unit to be retired will be 51 years old, with an average capacity of 109 Mw (versus 278 Mw for units that will continue operation), and has operated only 56% of the time.[75]

Some of these units will be replaced by new capacity, of which some will be coal-fired, but most replacements are likely to be natural gas combined cycle units. Even before the advent of the "train-wreck" rules, very few coal-fired plants were being built. As shown in **Figure 6**, since 1990, more than 80% of new capacity has been natural gas-fired. These plants are highly efficient; they are cost-competitive with coal; and they emit no SO_2, no mercury, and no other hazardous air pollutants. Without scrubber sludge to manage, they also do not need to meet effluent guidelines. Natural gas-fired power plants also have an advantage with regard to greenhouse gas (GHG) emissions: for the same amount of electric generation, they emit only half the GHGs of coal-fired units.

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[74] Data obtained from Sue Tierney, "EPA Proposed Utility Air Toxics Rule –Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, p. 4. Hereafter, "Tierney presentation." Additional calculation by CRS.

[75] Utility MACT RIA, p. 8-17.

In the last two years, gas has enjoyed a price advantage, as well. As one analyst notes:

> Since most of America's utilities have the ability to employ natural gas fired power plants in lieu of coal fired power plants when natural gas is priced advantageously, utilities have been ramping up natural gas consumption and reducing their usage of coal. With the price of Central Appalachian (CAPP) coal currently trading at $73 per ton, up from $60 per ton for much of last year, a recent study by Credit Suisse (CS) indicates that natural gas prices would need to rise to approximately $6.30 per mcf [thousand cubic feet] before coal and natural gas trade at parity for electricity generation.[76]

Gas is currently trading at around $4.50 per mcf, with futures contracts through 2014 generally trading below $6.00.[77]

Train Wreck?

Is there a train wreck coming for coal-fired power? The answer depends on the individual facility. Older, smaller, less efficient units already face a train wreck. In 2010, 48 of them with a combined capacity of 12 GW were retired, according to one source.[78] Another source identifies 149 coal-fired units with a combined capacity of 19.7 GW whose retirement has been announced or implemented in the past few years.[79] In recent weeks, as utilities weigh the cost of retrofitting and operating their older units, more retirements have been announced.[80]

[76] Bill Powers, "Natural Gas vs. Oil and Coal," *Financial Sense*, February 1, 2011, at http://www.financialsense.com/contributors/bill-powers/natural-gas-vs-oil-and-coal.

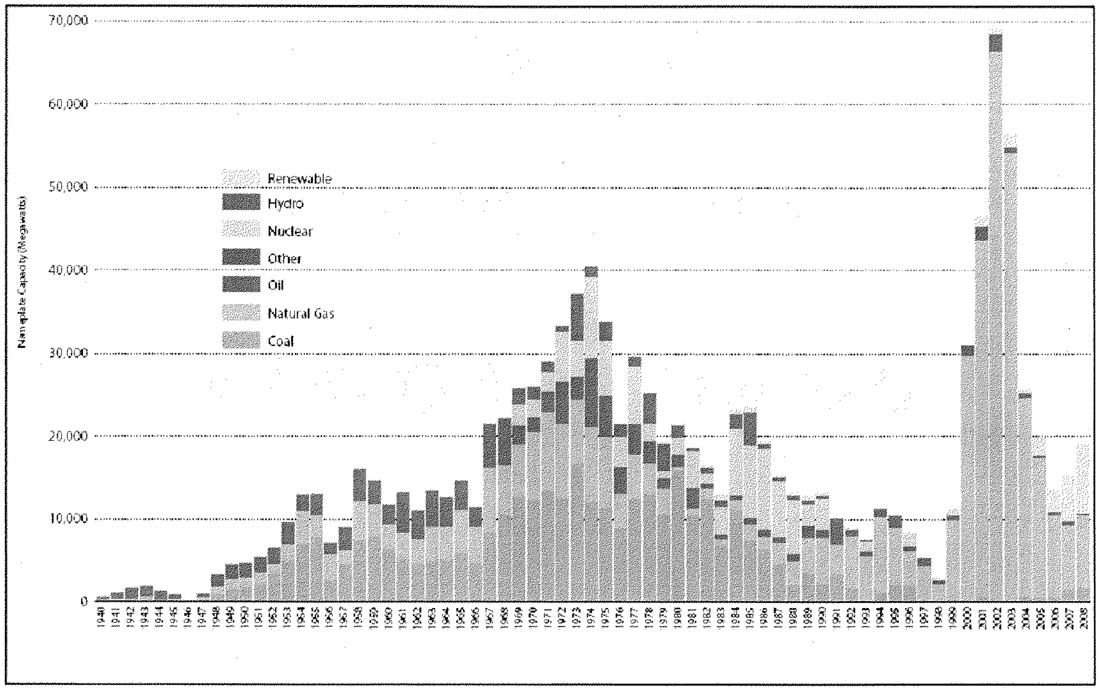
[77] Commodity Futures Price Quotes for NYMEX Natural Gas, at http://futures.tradingcharts.com/marketquotes/NG.html.

[78] Sierra Club, "2010, Outlook Dimmed for Coal: Year End State of Coal Report," Press Release, December 22, 2010, at http://action.sierraclub.org/site/MessageViewer?em_id=192801.0.

[79] See Source Watch, "Coal Plant Retirements," at http://www.sourcewatch.org/index.php?title=Coal_plant_retirements#Table_1:_Age_of_U.S._Coal_Plants. Of the 149 units listed, all but 15 were built before 1973.

[80] American Electric Power announced in early June that it will retire 6 GW of coal-fired capacity, about one-fourth of the capacity of its coal-fired fleet, and will retrofit an additional gigawatt to burn natural gas. TVA, in April, announced that it will retire 18 coal-fired units, replacing them with low emission or zero-emission electricity sources, including renewable energy, natural gas, nuclear power, and energy efficiency.

Figure 6. Power Plant Capacity, by Type and Year It Entered Service



Source: Sue Tierney, "EPA Proposed Utility Air Toxics Rule –Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, p. 10. The chart is based on EIA Form 860 data. A similar chart produced by EIA itself can be found at http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

But this does not mean that the newer (post-1970) coal-fired facilities that have invested in pollution controls over the years will be shuttered. Most of them already comply with many of the proposed rules, or if not, they can do so with modest modifications to their pollution control equipment. A train wreck for this group seems unlikely.

In between the two ends of the spectrum are facilities that are efficient enough or play a sufficiently vital role in meeting regional demand that the economics likely would justify their retrofit. For these facilities, the key questions are whether there will be sufficient time to act, and whether the reliability of the electric grid will be affected as they are taken off-line for modification.

Timing and Reliability Issues

It is difficult to generalize about the timing and system reliability issues. Several utilities state that they will have difficulty meeting the deadlines. In congressional testimony, April 15, 2011, Thomas A. Fanning, the Chairman, President, and Chief Executive Officer of The Southern Company, which provides electricity to 4.4 million customers in the Southeastern United States, stated:

> The reliability of the nation's electric generating system is at risk because of the number of new rules and regulations applicable to power plants. The stringency of these regulations, the lack of flexibility likely to be provided within these regulations, and, above all, the compliance schedules that will be required put reliability at risk. Accelerated plant retirements and shutdowns triggered by the Utility MACT rule will cause reserve capacity to plummet, increasing the likelihood and severity of service disruptions.[81]

In announcing the retirement of one-fourth of its coal-fired generation, June 9, 2011, American Electric Power's Chairman and CEO, Michael G. Morris, in a press release, stated:

> We support regulations that achieve long-term environmental benefits while protecting customers, the economy and the reliability of the electric grid, but the cumulative impacts of the EPA's current regulatory path have been vastly underestimated, particularly in Midwest states dependent on coal to fuel their economies. We have worked for months to develop a compliance plan that will mitigate the impact of these rules for our customers and preserve jobs, but because of the unrealistic compliance timelines in the EPA proposals, we will have to prematurely shut down nearly 25 percent of our current coal-fueled generating capacity, cut hundreds of good power plant jobs, and invest billions of dollars in capital to retire, retrofit and replace coal-fueled power plants.[82]

Others, however, cite historical experience and available indicators to argue that timing and system reliability will not be a problem. Michael Bradley, representing the Clean Energy Group, a coalition of electric power companies with over 200 GW of electric generating capacity, including 105 GW of fossil-fuel fired capacity, testified that:

[81] Testimony of Thomas A. Fanning, "Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities," Hearing, House Energy and Commerce Committee, Subcommittee on Energy and Power, April 15, 2011, p. 13.

[82] "AEP Shares Plan For Compliance With Proposed EPA Regulations," press release, June 9, 2011, at http://www.aep.com/environmental/news/?id=1697.

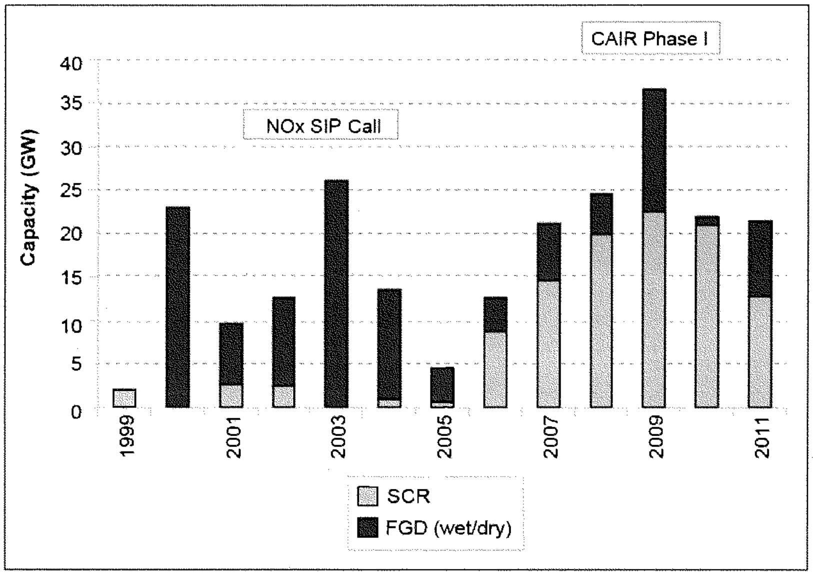
> The Utility Toxics Rule provides the business certainty the electric sector needs to move forward with capital investment decisions;
>
> • While not perfect, the proposal is reasonable and consistent with the requirements of the Clean Air Act;
>
> • The electric sector is well positioned to comply; and
>
> • The Clean Air Act provides sufficient time to comply as well as the authority to accommodate special circumstances where additional time is necessary.[83]

The Institute of Clean Air Companies, which represents the pollution control industry, states that utilities installed 60 GW of scrubbers and 20 GW of selective catalytic reduction (SCR) between 2008 and 2010. (See **Figure 7**.) In the early 2000s, in response to the NOx SIP Call, the industry installed 96 GW of SCR in a five-year period while successfully maintaining system reliability. This was a "much more capital and manpower intensive effort" than the Utility MACT will be, according to David Foerter, the group's Executive Director.[84]

[83] Testimony of Michael Bradley, "Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities," Hearing, House Energy and Commerce Committee, Subcommittee on Energy and Power, April 15, 2011, p. 1

[84] David C. Foerter, Executive Director, Institute of Clean Air Companies, "EPA's Proposed Utility Air Toxics Rule," Presentation to Congressional Staff, May 9, 2011, p. 6.

Figure 7. Cumulative SCR and Scrubber Installations, by Year



Source: David C. Foerter, Executive Director, Institute of Clean Air Companies, "EPA's Proposed Utility Air Toxics Rule," Presentation to Congressional Staff, May 9, 2011.

Notes: SCR = Selective Catalytic Reduction technology to reduce NOx emissions. FGD = Flue Gas Desulfurization, commonly referred to as a scrubber.

If necessary, as shown in **Figure 6**, the industry is capable of adding new generating capacity in a short time. From 2000-2003, electric companies added over 200 GW of new capacity, far more than any of the analyses suggest will be needed in the 2011-2017 timeframe.

A December 2010 analysis by FBR Capital Markets concluded that even the incremental retirement of 45 GW by 2014 (which appears to be more than EPA's rules will effect) would have little effect on electricity reserve margins:[85] "Summer reserve margins are currently 26% across the U.S. and are likely to decline only to 24% by 2014 in a draconian scenario in which 45 GW of generation is retired."[86] FBR offers the caveat that electricity reserve margins are a regional, not a national matter; but its analysis of eight NERC regions found reserve margins of 16.8% to 37.8% under its "draconian" 2014 scenario.[87]

Other studies suggest that proper planning can prevent a train wreck, even in worst-case scenarios. Much depends on whether individual utilities have already begun planning for the

[85] Only three of EEI's nine scenarios resulted in that many retirements, and all three assumed regulations far more stringent than EPA has proposed.

[86] FBR Capital Markets, *Coal Retirements in Perspective – Quantifying the EPA Rules*, December 13, 2010, p. 18.

[87] Ibid., p. 19. NERC considers 15% to be the necessary planning reserve margin. See NERC, "Reliability Indicators: Planning Reserve Margin," at http://www.nerc.com/page.php?cid=4%7C331%7C373.

implementation of the rules, including lining up engineers to design modifications, and conducting preliminary discussions with permitting authorities and grid operators regarding the required steps. This point is stressed by analysts on all sides of the issue. For example, Sue Tierney, after reviewing several studies, states:

> The studies' results do not mean that there will be resources gaps; they make it clear that action needs to be taken soon
>
> - These studies serve as a "call to action" ...
> - Several are explicit in saying that they have identified resource gaps in order to signal that action is needed.[88]

NERC's study is one of those to which Tierney refers. NERC concluded that, "Regulators, system operators, and industry participants should employ available tools to ensure Planning Reserve Margins while forthcoming EPA regulations are implemented."[89] Perhaps more importantly, it stated: "NERC should further assess the implications of the EPA regulations as greater certainty or finalization emerges around industry obligations, technologies, timelines, and targets."[90] Given that the NERC study assumed far more stringent requirements than EPA proposed for both the Cooling Water Intake and Utility MACT rules, a NERC reassessment could be informative.

On August 1, 2011, in response to a letter from Senator Lisa Murkowski, the Federal Energy Regulatory Commission (FERC) weighed in on the debate over reliability. FERC stated that its "... preliminary assessment showed 40 GW of coal-fired generating capacity 'likely' to retire, with another 41"GW 'very likely' to retire ...."[91] FERC did not reach conclusions as to whether such retirements would cause reliability problems, and it went to some lengths to stress the limitations of its analysis. Of particular note, despite the August 1 date, FERC's analysis was not based on information available at that time. It assumed that once-through cooling water systems would have to be replaced with closed-loop systems,[92] for example, which is not what EPA had proposed in March 2011. The analysis also did not take into account EPA's July finalization of the Cross-State Air Pollution Rule, which, in comparison to the earlier (proposed) version of the rule, provided additional flexibility for compliance. The Chairman's letter concluded: "... this informal assessment offered only a preliminary look at how coal-fired generating units could be impacted by EPA rules, and is inadequate to use as a basis for decision-making, given that it used information and assumptions that have changed."[93]

Price and Availability of Natural Gas

The EEI and NERC reports said that EPA rules would make coal-fired power more expensive so that utilities would retire additional coal-burning units (i.e., beyond those they already plan to retire) and replace them with alternative generation that emits fewer pollutants, leading to a drop

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[88] Tierney presentation, p. 9.

[89] NERC report, p. VII.

[90] Ibid.

[91] "FERC Response to Senator Murkowski, Proposed EPA Rule," Attachment to letter of Jon Wellinghoff, FERC Chairman, et al., to Hon. Lisa Murkowski, August 1, 2011, p. 5.

[92] Ibid., p. 2.

[93] Ibid., cover letter, p. 1.

in coal-fired generation and equal or greater increase for natural gas. From one perspective, the train wreck debate appears to be a coal-vs.-natural gas argument. The debate is not entirely that simple, however, because gas-burning power plants will be subject to some of the new rules, too. Some rules may affect coal-fired power plants disproportionately compared with other plants, while other rules, such as the cooling water intake proposal, may affect non-coal-fired power plants to a greater extent.

The primary impacts of many of the rules discussed here will be on coal-fired plants more than 40 years old that have not, until now, installed state-of-the-art pollution controls. Many of these plants are inefficient and are being replaced by more efficient combined cycle natural gas plants.

In EEI's analysis (and perhaps in the others that use the Integrated Planning Model[94]), a key variable is the assumed price of natural gas. The price of gas in EEI's reference case rises somewhat compared to today's price of about $4.50 per MMBtu, but it remains below $6.00 per MMBtu every year from now until 2035.[95] This is inexpensive gas, by the standards of recent history, as much as one-third below the price in each of the years 2004-2008. The low prices apparently reflect recent reports that future supplies of gas are projected to be abundant.[96]

In the other scenarios modeled by EEI (i.e., the scenarios showing the impact of EPA's expected regulations), the gas price ranged from about $5.50 to $7.50 per MMBtu over the 25 years through 2035. The higher prices presumably are the result of increased demand as some EGUs switch from coal to gas as a compliance strategy. These prices would also be below 2004-2008 prices in most cases.[97]

What the model showed in most of EEI's scenarios, then, is that, because the price of gas was projected to remain low, coal-powered units would be retired or converted to natural gas as EPA imposes the regulatory requirements under consideration.

Two of EEI's scenarios, however, used different assumptions regarding gas prices: they artificially assumed that gas costs either $1.50 or $3.00 per MMBtu more than the model's supply curve showed. With more expensive gas, fewer coal-powered facilities would be retired: in the extreme ($3.00 more) case, 17 GW were retired, compared to 57-71 GW in the same case with lower-priced gas.[98]

What these scenarios tell us is that utilities will look at the impending regulations and decide what to do largely based on their assumptions regarding the cost of the alternatives—natural gas (where it's available) being the most often discussed, but others include conservation, wind, and other renewable resources. If they expect the price of gas to remain low or the cost of other alternatives to be competitive, their primary method of compliance likely will be to retire old coal plants and switch to gas or the alternatives. If they expect the price of gas or other alternatives to be high, they'll invest the money in retrofitting the coal plants to reduce their emissions.

[94] The Integrated Planning Model, developed by ICF Inc., is used by EPA, EEI, and others to model the impacts of environmental regulations on the electric power industry.

[95] Natural gas price projections are shown on page 58 of the EEI report.

[96] The comparison is to EIA data shown in **Figure 4** above.

[97] All the scenarios, including the Reference case, assume a brief price peak in 2015, with prices declining for the next 15-20 years thereafter.

[98] EEI report, Table 3.1.

As the NERC report stated:

> Unit retirement is assumed when the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power.... For the purpose of this assessment, replacement power costs were based on new natural gas generation capacity. If the unit's retrofit costs are less than the cost of replacement power, then the unit is marked to be upgraded and retrofitted to meet the requirements of the potential environmental regulation., i.e., it is not considered "economically vulnerable" for retirement.[99]

As utilities attempt to forecast the price of natural gas, their conclusions will be based in large part on assumptions as to whether gas will be available in sufficient quantities to meet the increased demands of electric power generation. Natural gas faces its own controversies, as domestic production increasingly relies on "unconventional" sources such as shale, from which gas is obtained by hydraulic fracturing. (For additional information on this practice, see CRS Report R41760, *Hydraulic Fracturing and Safe Drinking Water Act Issues*, by Mary Tiemann and Adam Vann.) Nevertheless, a 2009 NERC report stated:

> Concerns regarding the availability and deliverability of natural gas have diminished during 2009 as North American production has begun to trend upward due to a shift toward unconventional gas production from shale, tight sands, and coal-bed methane reservoirs. In its latest biennial assessment, the Potential Gas Committee increased U.S. natural gas resources by nearly 45 percent to 1,836 TCF [trillion cubic feet], largely because of increases in unconventional gas across many geographic areas. Pipeline capacity has similarly increased, by 15 BCFD [billion cubic feet per day] in 2007 and 44 BCFD in 2008, with an increase of 35 BCFD expected in 2009. Storage capacity has also increased substantially.[100]

In short, the "train wreck" facing the coal-fired electric generating industry, to the extent that it exists, is being caused by cheap, abundant natural gas as much as by EPA regulations. As John Rowe, Chairman and CEO of Exelon Corporation, recently stated: "These regulations will not kill coal.... In fact, modeling done on the impacts of these rules shows that up to 50% of retirements are due to the current economics of the plant due to natural gas and coal prices."[101]

Legislation

Congress has shown a great deal of interest in the forthcoming EPA power plant rules and related Administration activities, with both proponents and opponents of EPA action circulating "Dear Colleague" letters and hearings held or scheduled by several House and Senate committees. Legislation to prevent or delay EPA action has passed the House, and more legislation is considered likely. Some recent proposals are broad in nature, targeting EPA generally or a lengthy list of specifics, while others focus more narrowly on individual rules or actions.

[99] NERC report, p. 6.

[100] NERC, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009, p. 4, available at http://www.nerc.com/files/2009_LTRA.pdf.

[101] John W. Rowe, "Energy Policy: Above All, Do No Harm," Remarks as Prepared, American Enterprise Institute, March 8, 2011, p. 7. Exelon is one of the largest electric and gas utility companies in the United States, serving 13 million people in Illinois and Pennsylvania.

One such broad bill is H.R. 2401, the Transparency in Regulatory Analysis of Impacts on the Nation (TRAIN) Act of 2011. It would establish a panel of representatives of federal agencies to report to Congress by August 2012 on the cumulative economic impact of a number of listed EPA rules, guidelines, and actions concerning clean air and waste management. The House Energy and Commerce Committee approved this bill on July 13. Similar legislation introduced in the Senate, S. 609, the Comprehensive Assessment of Regulations on the Economy Act of 2011, would direct the Department of Commerce to form a panel to review the cumulative energy and economic impacts of specific rules proposed or finalized by EPA or expected soon. Both bills would cover rules discussed in this report. Impetus for this type of legislation is the widely expressed concern that when EPA analyzes impacts of individual regulations, it does not consider costs imposed by multiple rules taking effect more or less simultaneously. Another bill, H.R. 1872 (the Employment Protection Act of 2011) would require EPA to consider the impact on employment levels and economic activity prior to issuing a regulation, policy statement, guidance, or other requirement, implementing any new or substantially altered program, or issuing or denying any clean water or other permit. Companion Senate legislation is S. 1292.

Even before the start of the 112th Congress, House Republican leaders signaled that House committees would scrutinize EPA's rulemaking decisions, including by withholding funding for prospective rules and de-funding previously promulgated rules.[102] This was demonstrated when the House passed H.R. 1, a full-year continuing appropriations resolution for FY2011, in February. As passed by the House, the bill contained more than 20 provisions restricting or prohibiting the use of appropriated funds to implement various regulatory activities under the EPA's jurisdiction—including many discussed in this report.[103] (On March 9, the Senate failed to approve the House-passed bill and subsequently also did not agree to a substitute text (S.Amdt. 49) that contained different funding levels and generally omitted the EPA regulatory provisions in the House-passed bill.) Final legislation that provided full-year appropriations for EPA (P.L. 112-10) did not include the restrictive provisions in the House-passed bill. Subsequently, many of these same provisions were included as general provisions in legislation providing FY2012 appropriations for EPA (H.R. 2584), which the House considered in July but took no final action on before Congress recessed in early August. As reported by the House Appropriations Committee, H.R. 2584 contains policy provisions that would, for example, prohibit EPA from spending appropriating funds to propose or promulgate rules for greenhouse gas emissions from stationary sources; to modify the PM NAAQS; to finalize or implement the cooling water intake rule; or to propose or implement a coal combustion ash rule. The bill also includes a provision similar to H.R. 2401, described above.

Several bills concerned with specific rules discussed in this report also have been introduced.

The House approved legislation to restrict EPA authority and to repeal a dozen EPA regulatory actions dealing with greenhouse gases (H.R. 910) on April 7. In the Senate, an amendment identical to H.R. 910 (S.Amdt. 183) failed on a vote of 50-50.

As discussed elsewhere in this report (**Appendix A**), EPA's January 2011 veto of a CWA permit for a West Virginia surface coal mining project has been very controversial, including in Congress, and raised questions about adequate coal supplies for power plants. In the 112th

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[102] Honorable Jerry Lewis, letter to EPA Administrator Lisa P. Jackson, November 29, 2010, on file with authors.

[103] For information, see CRS Report R41698, *H.R. 1 Full-Year FY2011 Continuing Resolution: Overview of Environmental Protection Agency (EPA) Provisions*, by Robert Esworthy.

Congress, legislation has been introduced to remove EPA's veto authority from the CWA (H.R. 517), and a number of other bills to modify or clarify this portion of the law also have been introduced (H.R. 457/S. 272, H.R. 468/S. 960, and H.R. 2018). A subcommittee of the House Transportation and Infrastructure Committee held hearings on these issues in May, and on July 13, the House passed H.R. 2018. Several provisions in this bill would limit EPA's authority to provide oversight of states' implementation of the CWA; it would allow the agency to veto a Section 404 permit only with concurrence of the state where the subject discharge originates. As passed, the bill also includes a provisions similar to H.R. 1872, described above; it would require EPA to consider economic impacts before promulgating any clean water rule, or issuing or denying a clean water permit.

Also in the 112th Congress, two bills have been proposed that would prohibit CCW from being regulated under Subtitle C of RCRA—H.R. 1391 (the Recycling Coal Combustion Residuals Accessibility Act of 2011, or the RCCRA Act) and H.R. 1405. On June 21, 2011, a House Energy and Commerce Committee subcommittee approved H.R. 1391.[104]

Beyond Congress, some state legislatures also have taken interest in EPA's regulatory activity. In February, the American Legislative Exchange Council issued a report identifying a number of strategies that states could use to oppose EPA's actions: adopting resolutions, conducting enhanced legislative review of state regulations, and enacting bills to assert state sovereignty.[105] Resolutions critical of EPA's actions have been introduced in several state legislatures this year.

Concluding Thoughts About the "Train Wreck" Analyses

EEI, NERC, and other recent reports describe scenarios and potential impacts of EPA rules, including projected need for additional power plant capacity or potential reliability problems, that depend on a number of assumptions such as the stringency of the rules or expected tight compliance deadlines, many of which differ greatly from what EPA has actually proposed or promulgated. Also, because most of the reports try to look collectively at EPA rules, to the extent a proposed or promulgated rule differs from some of these assumptions, it can be difficult to separate out one rule's projected impacts from the report's overall conclusions about multiple rules.

Some of the reports project impacts on power plants and electricity supply nationwide, some project impacts on a regional basis. In reality, evaluating regulatory impacts, compliance costs, and possible retirement decisions depends on facility-specific considerations—micro, not macro. Utilities and states will be affected differently. Rules when actually proposed or issued may well differ enough that investment or retirement decisions look entirely different. Technology options available to a unit or plant depend on the specific rule, and compliance costs may be less than

[104] For more information, go to the House Energy and Commerce Committee hearing web page, "Fossil Fuel Combustion Waste Regulation," http://republicans.energycommerce.house.gov/hearings/hearingdetail.aspx?NewsID=8474.

[105] American Legislative Exchange Council, "EPA's Regulatory Train Wreck, Strategies for State Legislators," February 2011, http://www.alec.org/AM/Template.cfm?Section=EPATrainWreck&Template=/CM/ContentDisplay.cfm&ContentID=15364. According to its website, the American Legislative Exchange Council is an organization of conservative state lawmakers.

projected. Even some units with high assumed control costs, or others that look to be marginal economically, may install controls and continue to operate. Many utilities have already installed technology needed to comply with new rules; for them, costs will be minimal: EPA said that, with regard to the most expensive proposed rule, the Utility MACT, more than half of the coal-fired units fall in this category. The EEI and NERC reports did not account for the fact that plants' compliance costs may be less because of investments already made in pollution control equipment.

Frequently overlooked in analyses of EPA regulations are the benefits to public health and the environment that will occur, benefits that for the most part are difficult to monetize. EPA does estimate benefits of individual rules, while acknowledging that it is challenging to quantify benefits due to data limitations and uncertainties in approaches used to value benefits. The costs of the rules may be large, but, in most cases, the benefits are larger, especially estimated public health benefits. Neither the EEI nor the NERC report addresses benefits.

Although much of the current critical attention to EPA's regulations has focused on rules affecting power plants, especially coal-fired power plants, the rules discussed here are only part of EPA's statutory mandate and regulatory agenda, and there are controversies about many of these other rules, as well, such as a MACT rule to control toxic air pollutants from commercial and industrial boilers and several Clean Water Act rules concerning water quality standards and permits.[106] Further, concerns about impacts of EPA rules have been raised by a range of individual companies and trade associations representing regulated entities beyond the electric utility sector, such as agriculture, chemical manufacturers, water utilities, and others.[107]

Several other conclusions bear repeating:

- The studies sponsored by industry groups (EEI and NERC) were written before EPA proposed most of the rules whose impacts they analyze, and they assumed that the rules would impose more stringent requirements than EPA proposed in many cases.
- Of the regulations so far proposed, the Utility MACT, which will set standards for power plant emissions of mercury and other hazardous air pollutants, appears to be the most expensive. EPA's analysis concluded that it will impose annual costs of $10 billion to $11 billion annually
- Other rules that industry expected to impose major costs now appear less likely to do so. The Cooling Water Intake rule, for example, proposes a less costly, more flexible regulatory option than EEI and NERC anticipated. Further, NERC believes that few coal-fired EGUs will be affected by this rule, which will have greater impact on older, oil-fired units. The Coal Combustion Waste Rule has been delayed, with no deadline for promulgation.
- For coal-fired plants, the primary impacts will be on units more than 40 years old that have not, until now, installed state-of-the art pollution controls. Many of

[106] For additional information, see CRS Report R41561, *EPA Regulations: Too Much, Too Little, or On Track?*, by James E. McCarthy and Claudia Copeland.

[107] Regarding agriculture's interest in EPA rules, see CRS Report R41622, *Environmental Regulation and Agriculture*, coordinated by Megan Stubbs.

these plants are inefficient, and are being replaced by more efficient combined cycle natural gas plants.

- Lower prices for natural gas and recent increases in its projected availability may reduce the impact of the proposed rules on electric utilities and consumers, although they may lead to more retirements of coal-fired units.
- There is a substantial amount of excess generation capacity at present, due in part to the recession and also due to the large number of natural gas combined cycle plants constructed in the last decade, muting reliability concerns.

Implementation

Finally, several other points regarding the timing of implementation of EPA rules are worth underlining:

- Many proposed and "pre-proposal" rules linger for years without being promulgated; thus, many of the EPA actions described here may not be finalized or take effect for some time. They may also be substantially altered before they become final (i.e., before sources of pollution actually are affected by control requirements), as a result of the proposal and public comment process, and/or judicial review.
- Although EPA generally announces a schedule under which it plans to propose and promulgate rules, experience suggests that proposal and promulgation may take longer than estimated, particularly in cases that do not have court-ordered deadlines.
- Even court-ordered dates for proposal or promulgation may change. It is not uncommon for EPA to request extensions of time, often due to the need to analyze extensive comments.
- Promulgation of standards is not the end of the road. Virtually all major EPA regulatory actions are subjected to court challenge, frequently delaying implementation for years. As noted earlier, many of the regulatory actions described here are the result of courts remanding and/or vacating rules promulgated by previous administrations.
- In many cases, EPA rules must be adopted by states to which the relevant program has been delegated. Moreover, many states require that the legislature review new regulations before the new rules would take effect.
- For many rules, actions by states may be more significant than what EPA does, because the CAA, CWA, and RCRA allow states to adopt more stringent requirements. For example, EPA's cooling water intake proposal does not mandate installation of costly closed-cycle cooling systems at all existing power plants. At the same time, an EPA rule does not preclude states from imposing such a mandate, as has occurred and is occurring in several locations (e.g., New York, California, Delaware, and New Jersey).
- Standards for stationary sources under the air, water, and solid waste laws are generally implemented through permits, which would be individually issued by state permitting authorities after the standards take effect. When finalized, a permit would generally include a compliance schedule, typically giving the

> permittee several years for installation of required control equipment. Existing sources generally will have several years following promulgation and effective dates of standards, therefore, to comply with any standards.

In short, the road to EPA regulation is rarely a straight path. There are numerous possible causes of delay. It would be unusual if the regulatory actions described here were all implemented on the anticipated schedule, and even if they were, existing facilities would often have several years before being required to comply. Unable to account for such factors, which will vary from case to case, timelines that show dates for proposal and promulgation of EPA standards effectively underestimate the complexities of the regulatory process and overstate the near-term impact of many of the regulatory actions.

Appendix A. Regulatory Actions Affecting Mountaintop Removal Mining

EPA and other federal agencies (the Office of Surface Mining and Reclamation, in the Department of the Interior; and the U.S. Army Corps of Engineers) are developing a series of actions and regulatory proposals to reduce the harmful environmental and health impacts of surface coal mining, including a practice called mountaintop removal mining, in Appalachia. These actions would not affect electric power plants directly, and thus were not covered by EEI nor NERC in their studies. Thus, CRS did not include these regulations in the discussion of the "train wreck" issues in the body of this report. Nevertheless, numerous critics of EPA have included EPA, Corps of Engineers, and Interior Department actions in what they term a "War on Coal." The actions, announced in a June 2009 interagency Memorandum of Understanding, are intended to tighten regulation and strengthen environmental reviews of permit requirements under the CWA and the Surface Mining Control and Reclamation Act (SMCRA).

Also in June 2009, EPA and the Army Corps signed a specific agreement detailing criteria that will be used to coordinate and expedite review of pending CWA permit applications for surface coal mining operations in Appalachia. The agencies are conducting detailed reviews of 79 permit applications to evaluate the permits in order to limit environmental impacts of the proposed activities. This review is proceeding slowly. In June 2010, the Army Corps suspended the use of a particular CWA general permit for surface coal mining activities in Appalachia and proposed a rule to prohibit its use entirely; a finalized rule, expected in 2012, would apply more stringent CWA rules to these coal mining operations.[108]

In April 2010 EPA released an interim guidance memorandum that seeks to clarify the agency's tightened requirements for surface coal mining in Appalachia. The guidance will be applied as a framework for EPA's approval of all pending and future reviews of permits to dispose of coal mining waste and other types of Appalachian surface coal mining discharges that are authorized by the CWA. Among other items, the interim guidance sets strict numeric limits on conductivity levels in waters affected by mining activities. Conductivity is a measure of the level of salinity in water associated with discharges of selenium and total dissolved solids that are associated with coal mining wastes. Based on recent scientific literature, EPA has concluded that conductivity above certain levels in Appalachian streams presents a reasonable potential to harm stream biota.

Conductivity, and its use in assessing coal mining impacts on water quality, has become a focus of debate. According to EPA, the 2010 interim guidance is not intended to bring a complete halt to surface coal mining in Appalachia, but to force the industry to adopt practices that will minimize harmful impacts. Environmental groups support the guidance document and EPA's use of conductivity to assess water quality impacts, but industry groups have been highly critical, asserting that the science linking conductivity to water quality impairment is uncertain and that acceptable numeric levels are arbitrary. Lawsuits challenging the guidance have been brought by the States of Kentucky and West Virginia, as well as individual coal companies and trade associations. In January 2011, a federal judge who is hearing one of the challenges denied industry's request to block implementation of the guidance, but also denied the government's

[108] U.S. Department of the Army, Corps of Engineers, "Suspension of Nationwide Permit 21," 75 *Federal Register* 34711-34714, June 18, 2010.

request to dismiss the case. EPA is working on revised guidance that incorporates public comments, scientific reviews, and experience of implementing the 2010 guidance. Final guidance had been expected by April 1, but its release has been delayed by interagency review.

In addition, in November 2009, the Department of the Interior's Office of Surface Mining (OSM) issued an Advance Notice of Proposed Rulemaking (ANPR) describing options to revise a SMCRA rule, called the stream buffer zone rule, which was promulgated in December 2008.[109] The Obama Administration identified the 2008 rule, which exempts so-called valley fills and other mining waste disposal activities from requirements to protect a 100-foot buffer zone around streams, for revision as part of the series of actions concerning surface coal mining in Appalachia. OSM identified a broad set of regulatory options that it is considering for revisions to the 2008 rule, ranging from formally reinstating the previous rule with small conforming changes, to requiring stricter buffer zone requirements for mountaintop mining operations on steep slopes. OSM officials have been working on developing a new rule, with the goal of releasing a proposal by early 2011, but none has yet emerged. In addition, EPA and OSM have pledged to strengthen oversight of state CWA and SMCRA permitting, regulation, and enforcement.

Finally, EPA has used CWA authority to veto a permit for a surface coal mining operation in West Virginia, after determining that the activity will have an unacceptable adverse effect on wildlife and fishery resources. EPA's veto has been very controversial, in part because it involves the rare action of cancelling a permit previously issued by the Army Corps. Coal industry groups and those representing manufacturing and other sectors have been highly critical, many saying that to revoke an existing permit creates huge uncertainty about whether water quality permits would be rescinded in the future, producing a ripple effect beyond the coal industry. EPA argues that the veto, while highly unusual, is justified because the project involves unacceptable environmental damages.

Viewed broadly, the Administration's combined actions on surface coal mining displease both industry and environmental advocates. The additional scrutiny of permits, more stringent requirements, and EPA's veto of a previously authorized project have angered the coal industry. At the same time, while environmental groups support the veto and related actions, many favor even tougher requirements.[110]

Critics assert that collectively the Administration's activities and initiatives concerning surface coal mining in Appalachia are needlessly delaying important projects, thus costing jobs and hurting the nation's energy security. While these actions do not directly affect power plants, they have the potential of doing so indirectly, if they effectively limit or restrict coal supplies. None of these actions are discussed in either the EEI or NERC analysis.

[109] U.S. Department of the Interior, Office of Surface Mining Reclamation and Enforcement, "Stream Buffer Zone and Related Rules; Advance notice of proposed rulemaking; notice of intent to prepare a supplemental environmental impact statement (SEIS)," 74 *Federal Register* 62664-62668, November 30, 2009.

[110] For additional information, see CRS Report RS21421, *Mountaintop Mining: Background on Current Controversies*, by Claudia Copeland.

Appendix B. Bibliography of Analytic Reports

Growing interest in the impact of EPA regulation on fossil-fuel power plants, especially coal-fired plants, has generated a large number of analytic reports by policy and advocacy groups using varying assumptions and analytic approaches that reach varying conclusions. Many of these reports were issued prior to proposal or promulgation of a rule.

North American Electric Reliability Corporation, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October 2010, http://www/nerc.com/files/EPA_Scenario_Final_v2.pdf.

ICF International, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, Final Report, prepared for Edison Electric Institute, January 2011, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf.

Metin Celebi, Frank Graves, Gunjan Bethla, et al., The Brattle Group, *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, December 8, 2010, http://www.brattle.com/_documents/uploadlibrary/upload898.pdf.

National Economic Research Associations, *Proposed CATR + MACT*, prepared for American Coalition for Clean Coal Electricity, May 2011, http://www.americaspower.org/NERA_CATR_MACT_29.pdf.

Dan Eggers, Kevin Cole, Yang Y. Song, and LinLin Sun, Credit Suisse, *Impact of EPA Rules on Power Markets*, September 2010, http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=b42de70d-b814-4410-831d-34b180846a19. Also see Dan Eggers, Credit Suisse, *Implications of EPA Policy*, April 2011, http://www.fbcinc.com/EIA/presentations/Eggers_04.26.11.pdf.

Wood Mackenzie, "Long-term Viability of Many U.S. Coal Plants at Risk," September 10, 2010, http://www.woodmacresearch.com/cgi-bin/corp/portal/corp/corpPressDetail.jsp?oid=2178098.

FBR Capital Markets, *Coal Retirements in Perspective—Quantifying the Upcoming EPA Rules*, December 13, 2010, http://jlcny.org/site/attachments/article/388/coal1.pdf.

Hugh Wynne, Francois D. Broquin, and Saurabh Singh, Bernstein Research, *Black Days Ahead for Coal: Implications of EPA Air Emissions Regulations for Energy & Power Markets*, July 21, 2010, http://grist.s3.amazonaws.com/eparegs/Bernstein%20-%20black%20days%20ahead%20for%20coal%20-%2007%2021%2010.pdf.

There also have been a number of recent analytic rebuttals to these reports:

Michael J. Bradley, Susan F. Tierney, Christopher E. Van Atten, et al., *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, August 2010, http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf and *Summer 2011 Update*, June 2011, http://www.mjbradley.com/documents/MJBA Reliability Report Update June 7 2011.pdf.

University of Massachusetts Political Economy Research Institute, James Heintz, Heidi Garrett-Peltier, Ben Zipperrer, New Jobs – Cleaner Air, Employment Effects Under Planned Changes to the EPA's Air Pollution Rules, February 2011, http://www.ceres.org/resources/reports/new-jobs-cleaner-air.

Susan F. Tierney and Charles Cicchetti, *The Results in Context: A Peer Review of EEI's "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet,"* Summary Report, May 2011, http://www.supportcleanair.com/resources/studies/file/Tierney-and-Cicchetti-EEI-Peer-Review-Summary-May-2011.pdf.

World Resources Institute, *Response to EEI's Timeline of Environmental Regulations*, November 2010, http://pdf.wri.org/factsheets/factsheet_response_to_eei_timeline.pdf.

Josh Bivens, Economic Policy Institute, *A Lifesaver, Not a Job Killer, EPA's proposed "air toxics rule" is no threat to job growth*, EPI Briefing Paper, June 14, 2011, http://w3.epi-data.org/temp2011/BriefingPaper312 (2).pdf.

Jennifer Macedonia, Joe Kruger, Lourdes Long, and Meghan McGuinness, Bipartisan Policy Center, *Environmental Regulation and Electric System Reliability*, June 13, 2011, http://www.bipartisanpolicy.org/sites/default/files/BPC%20Electric%20System%20Reliability.pdf

Daniel J. Weiss, Valeri Vasquez, and Stewart Boss, "Mercury Falling, Many Power Plants Already Have Equipment to Slash Mercury, Toxic Contamination," June 21, 2011, http://www.americanprogress.org/issues/2011/06/mercury_falling.html.

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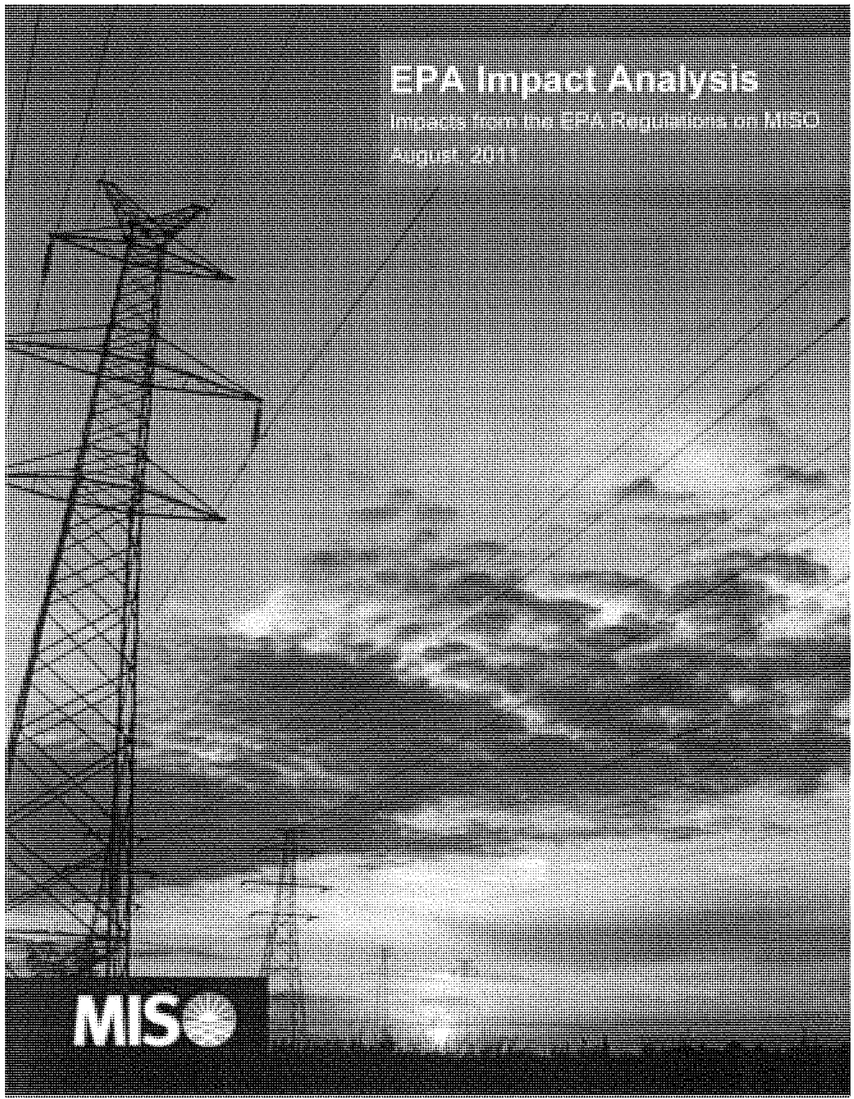

EPA Impact Analysis
Impacts from the EPA Regulations on MISO
August, 2011
MISO

Contents

1 Study Disclaimer

The objective of the MISO EPA Impact Analysis is to inform stakeholders. MISO does not intend nor has the authority to direct generation unit strategies. That authority belongs to the individual asset owners, only. The MISO analysis attempts to provide an overview of the impacts from the MISO regional perspective. Any subregional evaluation of the data would be an incorrect interpretation and application of the results.

The detailed results of the analysis were derived from a limited set of economic assumptions that included low demand and energy growth, low gas prices, and variation of carbon prices with sensitivities performed on gas and carbon prices. It should be expected that retirement impacts can change with different assumptions for these variables. The study also assumes that the natural gas transmission system is sufficient to accommodate the increased dependence on the natural gas fleet. This report attempts to address some of those issues, but is not able to capture all potential future outcomes. To get a better understanding of impacts associated with changing inputs and risks associated with the uncertainty of carbon, additional analysis would need to be performed.

2 Executive Summary

The United States Environmental Protection Agency (EPA) is finalizing four proposed regulations that will affect the MISO system. They require utilities to choose between retrofitting their generators with environmental controls and retiring them. At the direction of its members, stakeholders and Board of Directors, MISO evaluated the potential impacts of the new regulations including potential impact of carbon requirements. This study evaluated the impacts on capacity cost, resource adequacy, cost of energy and transmission reliability.

The 4 proposed EPA regulations are:

- Cooling Water Intake Structures (CWIS) – section 316(b) of the Clean Water Act (CWA)
- Coal Combustion Residuals (CCR)
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR)
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT)

2.1 EPA Impact Results Summary

A survey of the current fleet within MISO revealed a number of generation units will be affected. Impacts ranged from the installation of control equipment and expected redispatch to meet emission budgets, to potential retirement of units where the costs to comply outweigh the benefits of continued operation. Figure 2-1 shows that there are 355 units affected by these four proposed regulations and that the majority of the units (55 percent) are affected by three or all four regulations.

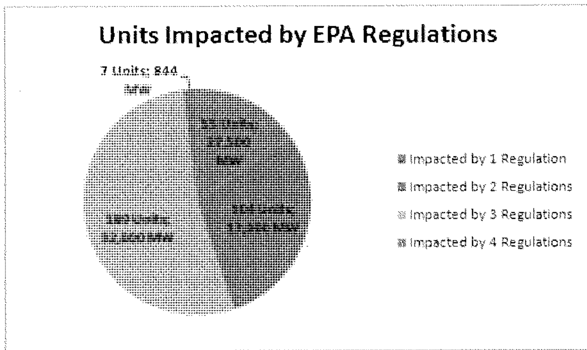


Figure 2-1: Number of Units Affected by EPA Regulations

The studies were conducted with the Electric Generation Expansion Analysis System (EGEAS) software package developed by the Electric Power Research Institute (EPRI) which is commonly used by utility generation planners. MISO performed over 400 sensitivity screens using with the EGEAS capacity expansion model to identify the units most at-risk for potential retirement. The sensitivities consisted of variation in gas costs, carbon costs and retrofit compliance costs. From those sensitivities, MISO identified nearly 13,000 MW of units at risk for retirement. Those units were offered to the EGEAS model as an economic choice to retrofit for compliance or retirement. The model makes this decision by comparing alternatives and selecting an expansion forecast that minimizes costs, including capital investment, production including emissions, and annual fixed operations and maintenance.

MISO ran two economic alternatives. The first evaluated a $4.50 natural gas cost, $0 cost for carbon, compliance for all the identified regulations and an expected cost for compliance with the regulations based on MISO stakeholder feedback through the study process. The second analysis provided the same assumptions but increasing costs of up to $50/ton for carbon production. The analysis on carbon costs was evaluated because judging the risk around the uncertainty of future carbon reduction requirements may cause asset owners to change their approach.

The results of the EGEAS analysis produced:

- **2,919 MW** at-risk for retirement at $4.50/MMBtu natural gas price and $0/ton carbon cost.
- **12,652 MW** at-risk for retirement with a $4.50/MMBtu natural gas cost and $50/ton carbon cost.

Using a suite of planning products, MISO's evaluation on the range of potential impacts indicates the following:

- Total 20-year net present value capital cost of compliance may range from **$31.6 billion** for 2,919 MW of retirement to **$33.0 billion** for 12,652 MW of retirement. Both values are in 2011 dollars and include the cost of retrofits on the system, the cost of replacement capacity, the cost of fixed O&M and the cost of transmission upgrades.
    - Capital costs for retrofits are **$28.2 billion and $22.5 billion**, respectively.

- Maintenance of the Planning Reserve Margin (PRM) is obligated under the MISO tariff. So it is expected that any capacity retirements would eventually be matched with replacement capacity to support PRM requirements. To maintain this requirement, it is estimated that the replacement costs would **$1.7 billion and $9.6 billion.**

- The annual fixed O&M impacts the total cost impact by **$1.1 billion and $0.0**, respectively.

- Retirement of units will have an impact on localized transmission system reliability. To ensure voltage and transmission thermal support on the system, an estimated **$580 million and $880 million**, respectively, of additional transmission upgrades could be necessary to maintain system reliability due to the identified potential unit retirements. The transmission numbers depend on location and any change from the study assumptions could result in different costs. Also, this assumes that any replacement capacity is not located at the retired unit locations. If replacement capacity is located at retired unit sites, it is likely the transmission upgrade costs will decrease.

- By replacing traditionally less reliable capacity with new resources, there is a potential that Planning Reserve Margin (PRM) requirements could decrease by having a more reliable fleet. Loss of Load Expectation (LOLE) analysis showed reductions of **0.2 to 1.0 percent**. However, if no replacement capacity is identified for resource adequacy purposes, then Loss of Load Expectation (LOLE) analysis shows that the LOLE on the system could be on the order of **0.21 to 1.028 days/year**. The current target is 0.1 days/year.

- There will also be an increase in the MISO load-weighted LMP of between **$1.2/MWh-$4.8/MWh** (2011$). This is driven by two key factors: (1) newly retrofitted units are less efficient because of the emission controls, and (2) retired coal facilities are replaced with natural gas fired capacity resulting in a greater dependence on the higher cost energy. These numbers exclude impacts of carbon costs on energy prices.

- Identifying all the costs to maintain regulation compliance and system reliability, a **7.0 to 7.6 percent** increase in current retail rates could be realized excluding the impacts of carbon on energy prices. If carbon costs are included in the generation production costs, the rate impact increases to a range of **37.2 to 37.7 percent**.

There is compliance risk associated with meeting the proposed regulations. As identified previously, additional investment in the generation fleet and the transmission system will maintain bulk power system reliability – at a cost. However, another risk that is not addressed directly within this analysis but should be mentioned is the time frame in which units must be compliant. Figure 2-2 demonstrates a high level time table of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take at least two to three years to build a combustion turbine to replace that capacity. Also, if transmission system reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to become operational. The time frame from final regulation to compliance may be difficult to meet for some situations throughout the system.

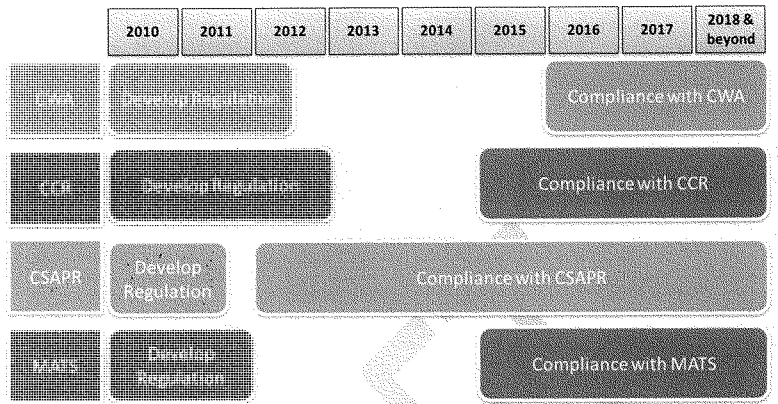


Figure 2-2: Estimated timeline for regulation development and implementation

2.2 Sensitivities Impact

Just as in the MISO Transmission Expansion Plan (MTEP), MISO uses a scenario planning process in the analysis and evaluation of these EPA regulations. Evaluating the impact over the EPA regulations requires that many conditions be considered separately and in combination with each other. MISO evaluated six scenarios with 77 sensitivities for each of the scenarios. The scenarios are:

- Base conditions, no new regulations
- Cooling Water Intake Structures section – 316(b) of the Clean Water Act (CWA)
- Coal Combustion Residuals (CCR)
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR)
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT)
- Combination of all 4 regulations

Figure 2-3 demonstrates the sensitivities evaluated for each regulation analysis. As there are 6 regulation scenarios there would be 6 branches to this decision tree, only the first branch is shown in Figure 2-3.

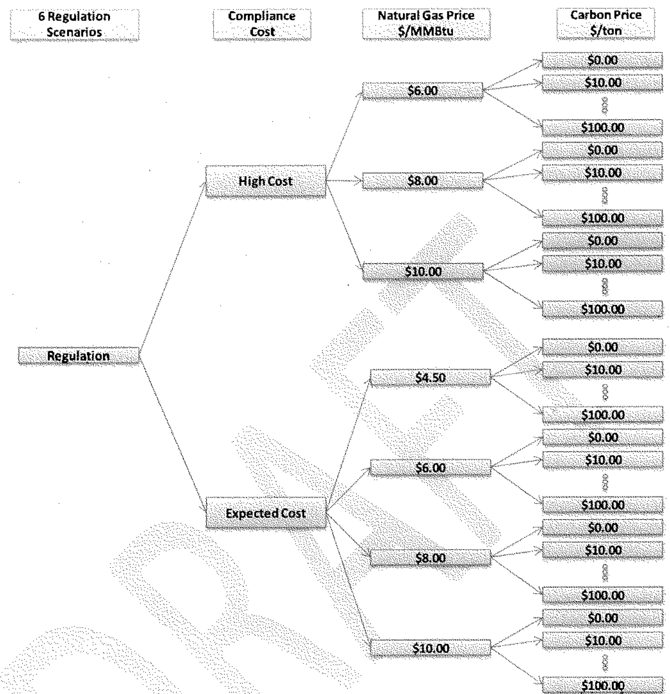


Figure 2-3: Decision Tree of EPA Cases

For each of the scenarios, 77 sensitivity cases consisting of two variations in compliance costs, natural gas costs and carbon price levels were modeled to produce a combined total of more than 400 sensitivity cases. The results indicated that up to 23,000 MW of coal capacity could be at-risk because of regulation compliance.

From these sensitivity cases, a few general conclusions can be made.

- **EPA Regulation impacts:** Compliance associated with the Mercury and Air Toxics Standards (MATS) produces the most at-risk units as its compliance costs and emission reductions have the greatest impact of the proposed regulations.

- **Compliance costs:** Higher compliance costs result in more at risk units. Evaluating all natural gas and carbon sensitivities for the high compliance cost cases resulted in up to 23,000 MW of at-risk capacity. However, running the same sensitivities at the more expected compliance costs as recommended and reviewed through the MISO stakeholder process, up to 13,000 MW of capacity was considered to be at risk.

- **Natural gas prices:** Lower natural gas prices produced more at-risk capacity than higher gas prices. The lower natural gas prices provide more incentive to retire capacity as the alternative resources provide competitive energy costs for the system. Conversely, when gas prices are high, the coal units find enough revenue on the system to cover compliance costs and keep general energy prices lower.

- **Carbon prices:** Adding cost to carbon puts economic pressure on units with higher carbon production rates. Because of this, higher carbon prices put more economic pressure on the coal units within the system, and the economics favor natural gas and carbon neutral capacity. So more coal units are at-risk for retirement with the higher carbon prices applied.

The units at-risk for retirement range from 0 MW to 23,000 MW based on the economic assumptions within the sensitivities. Cases where no units were identified to be at-risk for retirement include low compliance costs, higher gas prices and no carbon costs applied. This occurs because it minimizes cost for compliance while increasing potential revenue within the energy market through higher natural gas prices. Cases that produce at-risk generation up to 23,000 MW include high compliance costs, low gas prices and varying levels of carbon costs.

Figure 2-4 depicts an example of the impacts of the compliance costs, gas costs, and carbon costs from the identified potential retirements of 2,919 MW.

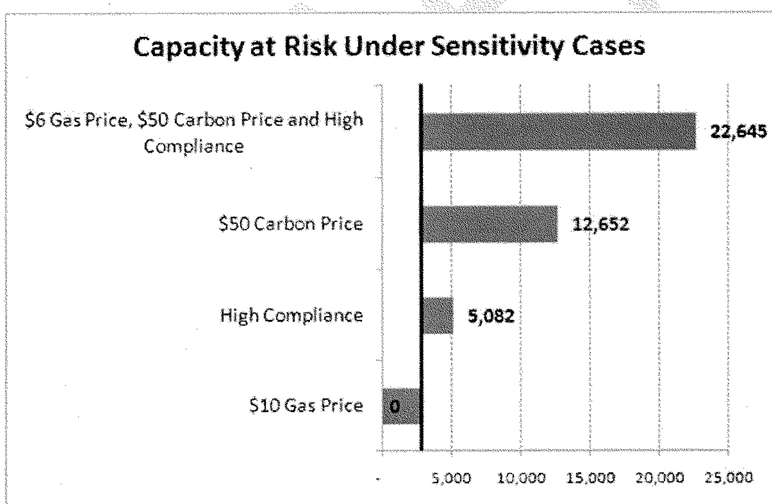


Figure 2-4: Tornado chart demonstrating the impacts of sensitivities on potential capacity retirements

2.3 Potential Carbon Regulation

At the end of 2010, the EPA issued a proposed schedule for establishing greenhouse gas (GHG) standards under the Clean Air Act for fossil fuel fired power plants and petroleum refineries. This is the first step the EPA is taking to address carbon. How that will unfold is not known. One of the ways for MISO to evaluate the impacts of carbon compliance is to add a cost to carbon that can represent either a carbon production tax or the effective costs to comply through reduction in carbon output by technology applications. This increases the dispatch cost in $/MWh for all units that produce carbon. Higher carbon emitting units receive a greater cost penalty that will change the order that all units in MISO are dispatched.

Figure 2-5, illustrates how the at-risk for retirement units increase because of the application of a cost for carbon. As the cost of carbon is increased to $50/ton, 12,652 MW's of units become at risk for retirement. This should be compared to the 2,919 MW identified without the carbon costs applied. This illustrates the importance of assessing the impact of future carbon in the analysis. If a unit would have spent money to retrofit for the EPA regulations, based on the assumption of no new carbon requirements, and carbon regulations materialize in the $35-$50/ton range, the investment becomes at risk at that later date.

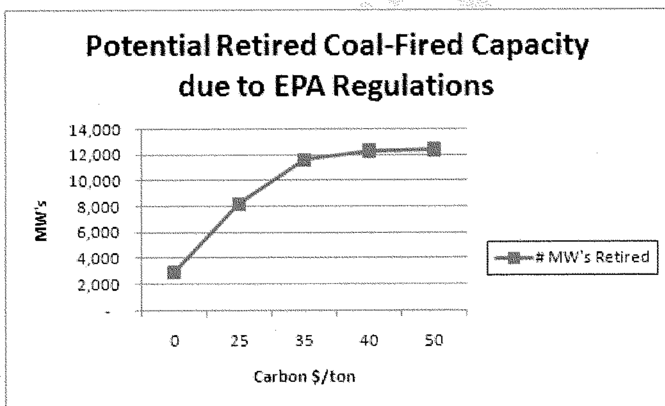


Figure 2-5: Carbon Impacts on Retrofit/Retirement Decision

2.4 Rate Impact

In general, the retail rates on the system are driven by the costs of generation production, generation capital costs, transmission capital costs and distribution capital costs. The MISO EPA regulation analysis identifies costs that impact three of the four components of the rates.

When the impact of carbon cost is excluded from the rate increase calculation, the greatest impact on the rates comes from the capital cost component. The capital cost increase comes in two forms, the EPA capital compliance cost and the capital cost for replacement capacity. Figure 2-6 demonstrates the comparison of the rate impact of the two retirement scenarios with the current average system rate. The overall increase in the rates because of compliance with the EPA regulations is approximately 7.0 to 7.6 percent.

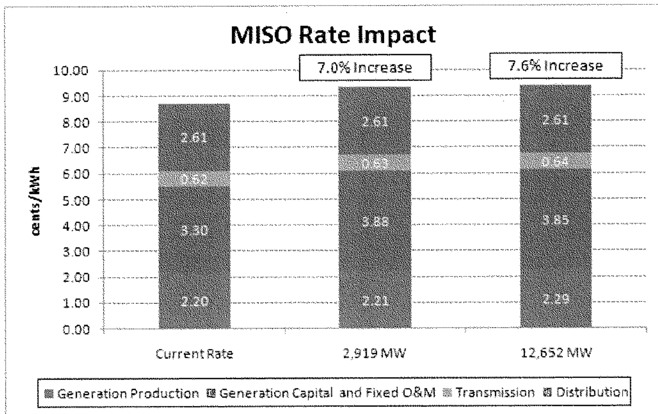


Figure 2-6: MISO Rate Impact excluding the cost of carbon in the production costs

Figure 2-7 demonstrates the rate impacts when a cost for carbon compliance is included in the generation production costs. In this comparison, the production costs are the primary driver for the rate increases that are 37.2 to 37.7 percent. The cost of carbon drives the retirements of 12,652 MW in this analysis. Applying the carbon cost to both scenarios demonstrates the total impact that carbon has on both capital investment and production costs.

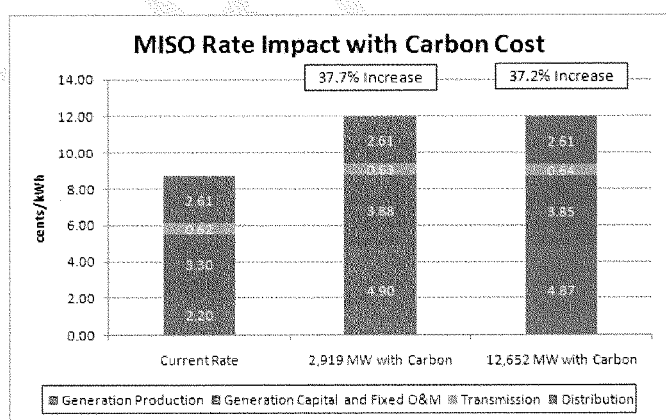


Figure 2-7: MISO Rate Impact including the cost of carbon in the production costs

3 EPA Regulations

The EPA is in the process of finalizing the following four proposed regulations that impact the electric industry:

- Cooling Water Intake Structures – section 316(b) of the Clean Water Act (CWA), final rule expected at the end of 2012
- Coal Combustion Residuals (CCR) , final rule expected at the end of 2011
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR) , rule finalized July 2011
- Mercury and Air Toxics Standards (MATS) formerly known as Electric Generating Unit (EGU) Maximum Achievable Control Technology (MACT) , final rule expected at the end of 2011

Each regulation is unique and has specific goals and as such MISO evaluated the impacts on its system for each regulation separately and also all four combined. The MISO study centered on determining the capacity cost impact, resource adequacy impact, energy cost impact and the transmission reliability cost impact on the MISO system.

3.1 Clean Water Act, Section 316(b)

Section 316(b) of the Clean Water Act (CWA) will establish the Best Technology Available (BTA) for Cooling Water Intake Structures to minimize impingement and entrainment of aquatic organisms. Currently it is a possibility that BTA could be defined as re-circulating cooling system retrofits for all units employing once-through cooling systems. This is likely a worst case scenario. In the MISO analysis BTA is defined as retrofits to re-circulating cooling systems only if the retrofit is drawing its cooling source from an ocean, tidal river or estuary.

3.2 Coal Combustion Residuals

The purpose of the CCR is to regulate the coal fly ash under one of two methodologies. The first methodology is to treat the ash as a special waste under subtitle C (hazardous waste) of the Resource Conservation and Recovery Act (RCRA). Under this option, facilities would need to close their surface ash impoundments within five years and dispose of the ash (past and future) in a regulated landfill with groundwater monitoring.

The second methodology is to regulate ash disposal as a non-hazardous waste under subtitle D of RCRA. This alternative would require the facility to remove the solids and retrofit the impoundment pond with a liner to protect against groundwater contamination and landfill coal combustion residuals disposal would require liners for new landfill and groundwater monitoring of existing landfills.

The second methodology is evaluated in this study.

3.3 Cross State Air Pollution Rule

The transport proposal reduces emissions that contribute to fine particle (PM2.5) and ozone non attainment that often travel across state lines, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) contribute to PM2.5 and ozone transport. The 28 states plus the District of Columbia are affected by transport rule and illustrated in Figure 3-1. The rule allows units in each state to meet the emissions targets in any way the state sees fit, including unlimited trading of emissions allowances between power plants within the same state with interstate trading permitted.

To assure emissions reductions happen quickly, EPA is proposing federal implementation plans, or FIPs, for each of the states covered by this rule. A state, however, may choose to develop a state plan to achieve the required reductions, replacing its federal plan, and may choose which types of sources to control.

Emission budget schedule implementation:

- Annual SO_2
  - Phase 1 group - 2012 cap that lowers in 2014
  - Phase 2 group - 2012 cap
  - Set emissions budget for each state
- Annual NO_x
  - 2012 state specific cap
- Ozone Season NO_x
  - 2012 state specific cap

The final CSAPR regulation came out just prior to the conclusion of this study. The analysis and results presented in the study are from previous proposals of what was known as the Clean Air Transport Rule (CATR).

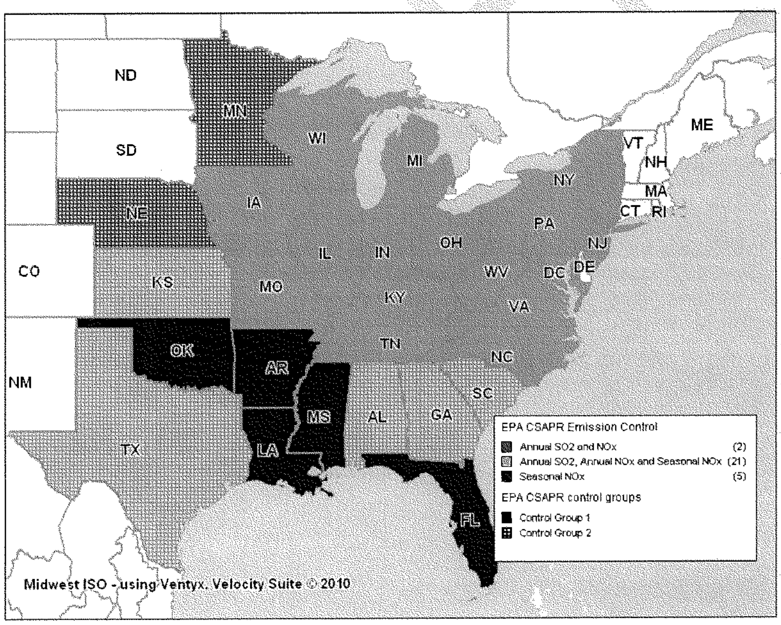


Figure 3-1: Cross State Air Pollution Rule Implementation

MISO

3.4 Mercury and Air Toxics Standards

The primary focus of the Mercury and Air Toxics Standards is the reduction of emissions from heavy metals and acid gases. The heavy metals include mercury (Hg), arsenic, chromium and nickel; and, the acid gases include hydrogen chloride (HCl) and hydrogen fluoride (HF). A final rule will be expected towards the end of 2011. The following represent a few key highlights of the proposal:

- For all existing and new coal-fired Electric Generating Units (EGUs), the proposed MATS regulations would set numerical standards for mercury, Particulate Matter (PM), and HCl
- For all existing and new oil-fired EGUs, the proposed toxics rule would establish numerical emission limits for total metals, HCl, and HF. Compliance with the metals standards is through fuel testing.
- For new units, proposed revisions to the New Source Performance Standards (NSPS) would include revised numerical EGU emission limits for PM, SO2, and NOX.

There are many technologies available to power plants to meet the emission limits, including wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and baghouses.

3.5 Regulation Timing

Figure 3-2 demonstrates a high level time table of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take a minimum of two to three years to build a combustion turbine to replace that capacity. Also, if transmission system reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to come into service. The time frame from final regulation to compliance may be difficult to meet for some situations throughout the system.

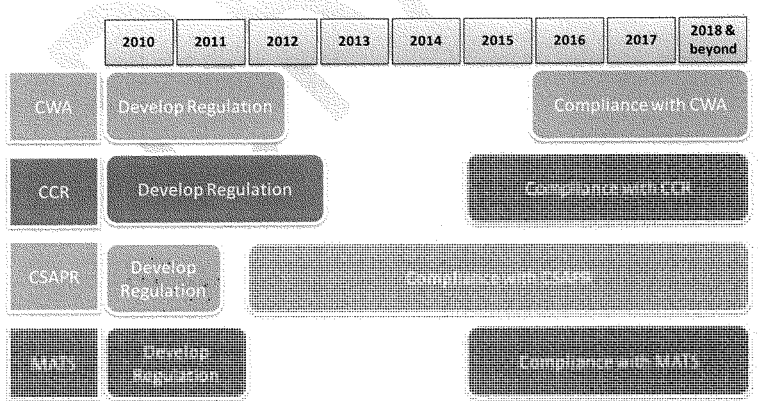


Figure 3-2: Estimated timeline for regulation development and implementation

3.6 Carbon Restrictions

There are currently no existing rules that regulate and reduce the amount of carbon being produced from the existing fleet. However, recent classification of carbon as a hazardous air pollutant obligates the EPA to regulate its production. There have also been proposals through the legislative process that have produced certain targets for the reduction of carbon. One of those proposals requires that the output of carbon should reduce by 40% from 2005 levels by 2030 and 83% by 2050.

4 Models

4.1 EGEAS

The Electric Generation Expansion Analysis System (EGEAS) software from the Electric Power Research Institute (EPRI) is used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. Optimizations can be performed on a variety of constraints such as resource adequacy (loss-of-load hours), reserve margins, or emissions constraints. The EPA study optimization is based on minimizing the 20-year capital and production costs, with a reserve margin requirement indicating when new capacity is required.

4.2 PROMOD IV®

PROMOD IV® is an integrated electric generation and transmission market simulation system that incorporates extensive details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations. It performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV® forecasts hourly energy prices, unit generation, fuel consumption, bus-bar energy market prices, regional energy interchange, transmission flows, and congestion prices. It uses an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, spinning reserve requirements, and customer demand.

4.3 PSS®E

PSS®E is an integrated, interactive program simulating, analyzing, and optimizing power system performance. PSS®E allows for detailed analysis of single hour operation based on defined system conditions such as system topology, demand and generation dispatch. This tool will allow the user to evaluate system reliability requirements in terms of both the transmission thermal limitations and required voltage levels at different points of the system.

4.4 GE-MARS

GE Energy's Multi-Area Reliability Simulation (GE-MARS) is a transportation-style model based on a sequential Monte Carlo simulation that steps through time chronologically and produces a detailed representation of the hourly loads and hourly wind profiles in comparison with the available generation, in addition to interfacing between the interconnected areas.

GE-MARS calculates, by area or area group, the standard reliability indices of daily or hourly loss of load expectation (LOLE, in days per year or hours per year) and expected unserved energy (EUE, in megawatt-hours per year).

The basic calculations are done at the area level, which is how much of the data are specified and aggregated. Loads, wind profiles, and generation are assigned to areas, and transfer limits are specified between areas.

5 Scope

The objective of the EPA Impact Analysis is to identify potential aggregate impacts of the EPA proposed regulations on the fleet within the MISO footprint. Specific key questions that are answered by the study are:

- Are there resource adequacy risks?
- Are there transmission adequacy risks?
- What are the impacts on the energy markets?
- What are the impacts on capital costs to the system?

Evaluation of study questions and results will be expressed at the MISO level, only. It is understood that retrofit/retirement decisions are the responsibility of the asset owners. MISO will not share unit specific information with any entity outside of the asset owner at their request.

Figure 5-1 shows the study scope. The study was comprised of 3 phases. The first phase screened the approximate 2,000 units in the MISO system to determine which of those units would be most at risk for retirement. The second phase used the results of the screening process to determine the energy and congestion impacts on the system. The third phase developed the compliance and capital cost requirements. The third phase also evaluated the impact of resource adequacy, system reliability and customer rates.

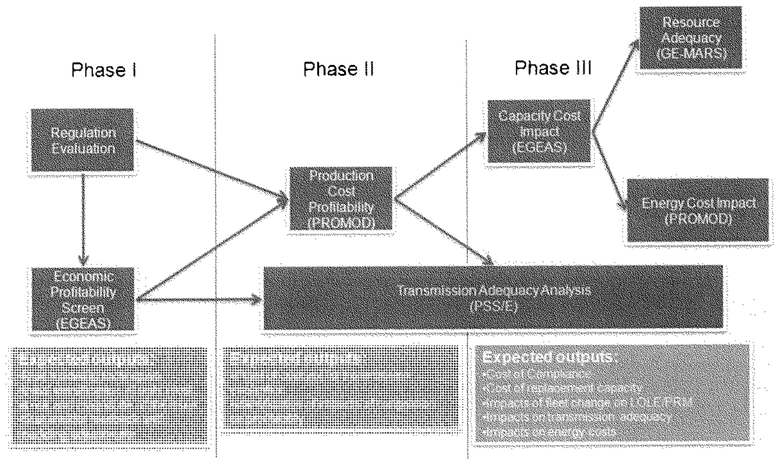


Figure 5-1: Flow Diagram of EPA Impact Analysis

6 Phase I

Phase I of the process consisted of three primary tasks: modeling techniques, profitability screening, and MISO stakeholder interaction. MISO researched the proposed regulations and recent evaluations of the regulations. The research focused on the development of the modeling techniques to be used within the various models. This included looking at various compliance technologies and their impacts on the operation and costs of units that may need to be retrofitted. MISO also surveyed asset owners on the control equipment already installed on the units.

The profitability screening utilized the EGEAS model. Existing system characteristics, compliance assumptions, and sensitivities on gas prices and costs for carbon regulation were applied. This resulted in over 400 screening cases to be run to identify potential at-risk for retirement units on the system.

Through the MISO Planning Advisory Committee, stakeholders were given the opportunity to comment on inputs and outputs from the screening runs. Through this feedback process, stakeholders provided suggestions on compliance technologies and costs that further enhanced the MISO analysis.

6.1 Phase I Assumptions

The MTEP 11 Business as Usual with Low Demand and Energy Growth Rate future was used as the base model in the regulation impact analysis. The demand growth rate was 0.78 percent and the energy growth rate was 0.79 percent. Both values are the effective growth rates determined through the MTEP process that include the impacts of projected demand response and energy efficiency resources. Detailed assumptions of the MTEP 11 futures can be found in Appendix E2 of the 2011 MTEP report.

The EGEAS model is used in Phase I because of the ability to run 20-year study cases in a quick and efficient manner. For the EPA Impact Analysis study MISO ran more than 400 EGEAS cases, representing sensitivities on combinations of the proposed regulations:

- Base conditions, no new regulations
- Cooling Water Intake Structures – section 316(b) of the Clean Water Act (CWA)
- Coal Combustion Residuals (CCR)
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR)
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT)
- Combination of all 4 regulations

Figure 6-1 demonstrates the sensitivities evaluated for each regulation analysis. As there are 6 regulation scenarios there would be 6 branches to this decision tree, only the first branch is shown in this graphic.

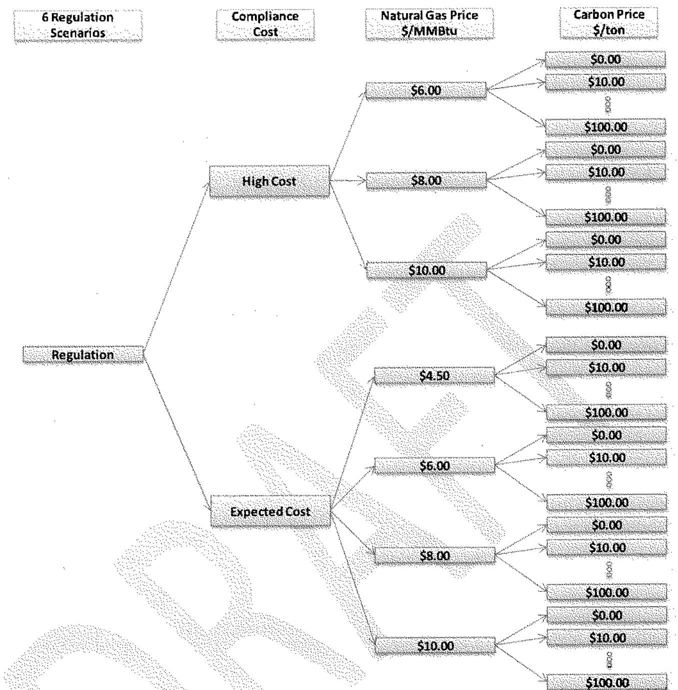


Figure 6-1: Decision Tree of EPA Cases (total of 77 sensitivities per regulation evaluated)

6.1.1 MATS, CWIS and CCR Assumptions

To increase the efficiency of the EGEAS analysis, a rule set was developed for which control technologies to model based on unit characteristics. This allows MISO to model the entire system and provide a reasonable set of alternatives for the retrofit versus retire comparisons. Table 6-1 demonstrates the rule set that was created.

The Great Lakes were considered as "oceans" for this analysis. This provided some impact of the intake structure regulation on the land locked footprint of MISO.

EPA Rule	Unit Type	Dry Scrubber	Dry Sorbent Injection	Activated Carbon Injection	Fabric Filter/Bag House	Recirculating Cooling	Fine Mesh Screens	Ash Conversion
MATS	Coal Units <=200MW		Yes	Yes	Yes			
	Coal Units >200 MW	Yes if no Wet Scrubber			Yes			
CWIS	Oceans, Estuaries or Tidal rivers					Yes		
	Not on Oceans, Estuaries or Tidal rivers						Yes	
CCR	Coal Units							Yes

Table 6-1: Retrofit Rule Set for EPA Regulations

Generating unit operating impacts due to installation of various control technologies were also introduced into the EGEAS model. Data was gathered from public sources and stakeholder feedback. Ultimately the values used in this EPA Impact Analysis were provided and agreed to by the stakeholders. Table 6-2 shows the generating unit operating impacts due to the installation of various control technologies.

Control Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Heat Rate (%)	Max Capacity (%)	Removal Rate (%)
Wet Scrubber	525 @ 500 MW	+20	+1	+1.5	-1	95% SO2 with .08 lbs/MMBtu floor
Dry Scrubber	450 @ 500 MW	+8	+1.5	+1.5	-0.7	90% SO2 with .08 lbs/MMBtu floor
Dry Sorbent Injection	40.6 @ 200 MW	+3.40	+8.7 Bituminous Coal +4.4 Lignite and Sub-Bituminous Coal	+.02	-.02	70% SO2 with .08 lbs/MMBtu floor
Activated Carbon Injection	275 @ 500 MW	+4	+1	N/A	N/A	90% Mercury
Fabric Filter/Bag House	150 @ 500 MW	N/A	N/A	N/A	N/A	90% PM
Recirculating cooling conversion	150 @ 500 MW	+1.5	N/A	+1.5	-1	N/A
Fine Mesh Screens	90 @ 500 MW	N/A	N/A	N/A	N/A	N/A
Wet to Dry Ash conversion	$30 Million + $80 w/ FGD or $200 w/o FGD	N/A	+1	N/A	N/A	N/A

Table 6-2: Unit Impacts due to Control Technologies

6.1.2 CSAPR Assumptions

The Cross State Air Pollution Rule (CSAPR) assumptions used within this report are from the preliminary numbers provided in the draft Clean Air Transport Rule (CATR). The recent CSAPR limits are more stringent than the limits applied in this study. There is a possibility that with the newer limits the impact is greater than seen in this report. The CSAPR regulation sets state wide emission limits for SO_2, NO_x, and NO_x Ozone. MISO is able to model state limitations within the EGEAS model. EGEAS will take those limits and dispatch the units in each state to meet the state limits. This closely models the unlimited intrastate trading with no interstate trading.

For this study EGEAS is run at an RTO/ISO level and as such some states might span across multiple RTO/ISO's. Just applying the state limit would cause the limit to be too high in some cases. An example would be a state that has 10 units but only 1 of the units is in MISO. That would mean one unit would have a limit set intended for 10 units. To accommodate multi-regional states, the emission limits were prorated by the capacity of the units in each RTO/ISO.

Table 6-3 demonstrates the state and region emission budgets under the draft CATR. These were the numbers applied to the impact analysis. The CSAPR was finalized in July 2011 and as such the numbers in the table below are not from the finalized rule. Initial analysis seems to suggest that the emission budgets are reduced for some states and re-categorized for other states.

State	RTO/ISO	Group #	2012-2013 SO2 Annual Limit (Tons)	2014+ SO2 Annual Limit (Tons)	2014+ NOX Annual Limit (Tons)	2014+ NOX Ozone Season Limit (Tons)
Alabama	SERC	II	113,285	113,285	49,262	21,179
Alabama	TVA	II	46,586	46,586	19,907	8,559
Arkansas	Entergy	II	-	-	-	14,876
Arkansas	SPP	II	-	-	-	1,784
Connecticut	ISONE	II	3,059	3,059	2,775	1,315
Delaware	PJM	II	7,784	7,784	6,206	2,450
District of Columbia	PJM	II	337	337	170	105
Florida	Florida	II	161,739	161,739	120,001	56,939
Georgia	SERC	I	233,260	85,717	73,801	32,144
Illinois	MISO	I	126,795	51,948	34,005	14,312
Illinois	PJM	I	82,162	58,582	22,035	9,168
Indiana	MISO	I	287,221	144,493	82,984	35,881
Indiana	PJM	I	113,147	58,919	32,883	14,126
Iowa	MISO	I	93,488	65,571	45,793	-
Iowa	MISO	I	564	317	276	-
Kansas	SPP	II	57,275	57,275	31,321	21,433
Kentucky	TVA	I	176,371	90,077	59,024	24,838
Kentucky	PJM	I	20,288	10,519	6,849	2,856
Kentucky	MISO	I	24,399	13,448	8,234	3,434
Louisiana	Entergy	II	87,125	87,125	32,604	15,741
Louisiana	Cleco	II	20,176	20,176	9,800	4,732
Louisiana	SPP	II	3,176	3,176	1,543	745
Maryland	PJM	II	39,665	39,665	17,044	7,232
Massachusetts	ISONE	II	7,902	7,902	5,960	-
Michigan	MISO	I	212,261	141,858	60,004	26,109
Michigan	PJM	I	19,076	11,916	4,928	2,144
Minnesota	MISO	II	47,101	47,101	41,502	-
Mississippi	SERC	II	-	-	-	5,198
Mississippi	TVA	II	-	-	-	4,872
Mississippi	Entergy	II	-	-	-	6,592
Missouri	MISO	I	85,851	66,769	24,295	-
Missouri	SPP	I	82,413	64,136	23,338	-
Missouri	TVA	I	35,625	27,784	10,098	-
Nebraska	SPP	II	71,598	71,598	43,228	-
New Jersey	PJM	II	11,291	11,291	11,826	5,169
New York	New York ISO	I	66,542	42,041	23,341	11,090
North Carolina	SERC	I	108,751	79,837	50,521	22,998
North Carolina	PJM	I	2,754	2,022	1,279	581
Ohio	PJM	I	388,571	148,244	80,906	33,806
Ohio	MISO	I	78,393	30,063	16,407	6,855
Oklahoma	SPP	II	-	-	-	35,055
Oklahoma	TVA	II	-	-	-	878
Pennsylvania	PJM	I	388,612	141,885	119,969	48,271
South Carolina	SERC	II	116,483	116,483	33,882	15,222
Tennessee	TVA	I	100,007	100,007	28,362	11,575
Texas	SPP	II	-	-	-	52,640
Texas	Entergy	II	-	-	-	23,544
Virginia	PJM	I	72,595	40,795	33,581	12,608
West Virginia	PJM	I	205,422	129,024	51,990	22,234
Wisconsin	MISO	I	96,419	66,683	44,845	-
Total			3,117,288	2,500,089	1,376,312	641,014

Table 6-3: State Emission Budget for draft CATR as used within the analysis

6.2 Phase I Results

To identify at-risk capacity on the system, MISO had to develop a methodology to evaluate the profitability of the units on the system. This was achieved through calculating the annual revenues and costs for each generating unit within MISO and determining the net margins for the units. The units with a net margin less than $0/kW were deemed to be either Tier I at-risk units or Tier II potentially at-risk units.

The net margin for each generating unit is calculated by subtracting annual costs from annual revenues. The next step is to list all the generating units in order of decreasing net margin for each year of the study period. From this ordered list of generating units, the marginal unit can be determined. The marginal unit is the unit at which the cumulative capacity equals the capacity requirements to meet the planning reserve margin (PRM) criterion. The offset adder expressed in $/kW is the required amount of net margin adder that will make the marginal unit whole. For example, as shown in Table 6-4, the net margin of the marginal unit, U_n, is -$450/kW, and the offset adder would be $450/kW to make the marginal unit whole. This offset adder is then applied to all units in the ordered list.

Unit	Net Margin	Capacity	Cumulative Capacity	Reserve Margin
U_1	$200/kW	400 MW	400 MW	
U_2	$175/kW	650 MW	1050 MW	
U_3	$130/kW	160 MW	1210 MW	
...	...	...	...	
...	...	...	...	
U_{898}	$0/kW	330 MW	100,000 MW	
U_{1000}	-$45/kW	80 MW	110,000 MW	
U_n	-$450/kW	125 MW	118,000 MW	17.40%
U_{n+1}	-$550/kW	30 MW	118,030 MW	17.4%+

Table 6-4: Pictorial Representation of Tier I and Tier II units

Two different sets of offset adders were calculated and used to determine which generating units are to be classified as Tier I and Tier II units. The Tier I offset adders are based on the EGEAS cases for each specific EPA Regulation, whereas the Tier II offset adders are based on the results of the EGEAS Base Case assuming no EPA Regulations, By definition, the Tier I offset adders are greater than the Tier II offset adders, since the Tier II offset adders do not include the added costs for the various EPA control systems needed to meet compliance. Table 6-5 provides an example of the Tiers. Units at risk are those at the bottom of the dispatch order where the revenue in-take may or may not cover the costs of compliance. Since MISO does not capture all revenue for a unit, this methodology provides reasonable cut-offs based on the PRM system reliability objective.

Unit	Net Margin from Regulation Case	Net Margin with EPA Regulation Offset Adder ($200/kW)	Net Margin with Base Conditions Offset Adder ($100/kW)	At-Risk Status
U1	$200/kW	$400/kW	$300/kW	Not at-risk
U2	$100/kW	$300/kW	$200/kW	Not at-risk
U3	$50/kW	$250/kW	$150/kW	Not at-risk
U4	$0/kW	$200/kW	$100/kW	Not at-risk
U5	-$50/kW	$150/kW	$50/kW	Not at-risk
U6	-$100/kW	$100/kW	$0/kW	Not at-risk
U7	-$150/kW	$50/kW	-$50/kW	Tier II
U8	-$200/kW	$0/kW	-$100/kW	Tier II
U9	-$250/kW	-$50/kW	-$150/kW	Tier I
U10	-$300/kW	-$100/kW	-$200/kW	Tier I

Table 6-5: Example of Tier I and Tier II identification

If a unit is identified as a Tier I unit in any of the sensitivity cases, it is classified as Tier I for the entire set of runs. Therefore, not any one scenario will result in the total identified Tier I list, but it is a combination of the unique units from all of the sensitivity cases.

6.2.1 High Compliance Cost Applications

MISO ran over four hundred sensitivities on the EPA regulations where Tier I and Tier II units were identified. Most of the sensitivities focused on combinations of gas and carbon prices. Those gas and carbon sensitivities were run on two variations of compliance with the EPA rules. Compliance with the rules was modeled at a high cost application and a more expected cost application. The differences in the two methods of modeling can be seen in Table 6-6.

High Cost Application	Expected Cost Application
Compliance costs applied in 2011 with 10 year recovery period	Compliance costs applied in 2015 with 20 year recovery period
SCR required to meet MATS	SCR **NOT** required to meet MATS
Closed loop cooling applied to all steam units	closed loop cooling applied to oceans, tidal rivers and estuaries
FGD applied to all units <=200MW	DSI applied to all units <=200MW
Carbon prices applied in 2011	Carbon prices applied in 2015
No $4.5/MMBtu gas price in sensitivities	$4.5/MMBtu gas price in sensitivities

Table 6-6: Modeling Differences between compliance modeling methodologies

Modeling of the compliance high cost application resulted in the identification of 102 Tier I coal units amounting to 5,082 MW of capacity and an additional 116 Tier II coal units amounting to 22,645 MW of capacity. Figure 6-2 provides a histogram of the units identified by Tier. As can be seen, the most at-risk units identified in Tier I are less than 200 MW while the Tier II units can get up to larger sizes. The modeling runs identify that the most at-risk units are a result of the application of compliance costs combined with lower gas prices where the higher values of those units in the Tier II list tend to show up as potentially at-risk because of the application of costs to carbon. It was also found through the sensitivity analysis that the MATS regulation is the primary driver in placing units at risk for retirement.

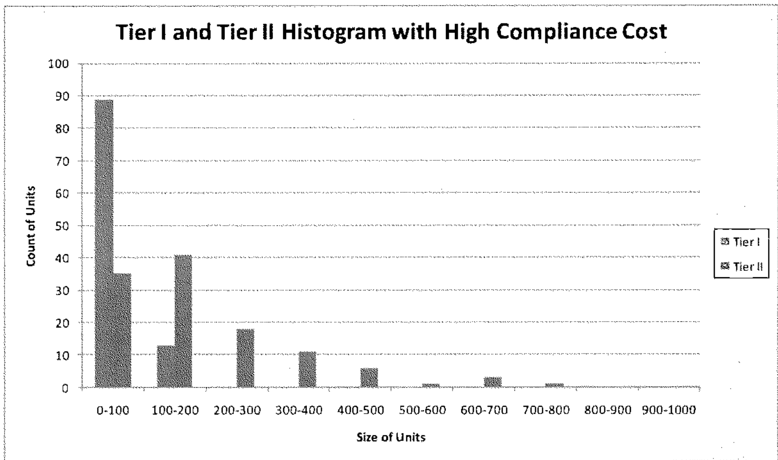


Figure 6-2: Tier I and Tier II Histogram high compliance cost application

6.2.2 Expected Compliance Cost Application

The modeling of the lower, more realistic compliance application reduced impacted generation on the Tier I and Tier II lists. In this set of sensitivity cases, Tier I accounts for 53 coal units amounting to 2,764 MW of capacity and Tier II accounts for an additional 98 coal units amounting to 9,885 MW of capacity. The adjustment in capacity cost modeling identifies more of the smaller coal units on the system as Tier II rather than Tier I as seen in the compliance cost application cases, Figure 6-2 and Figure 6-3. The expected compliance cost application also identifies no units greater than 300 MW in either of the Tiers. The average age of the units identified is 52 years.

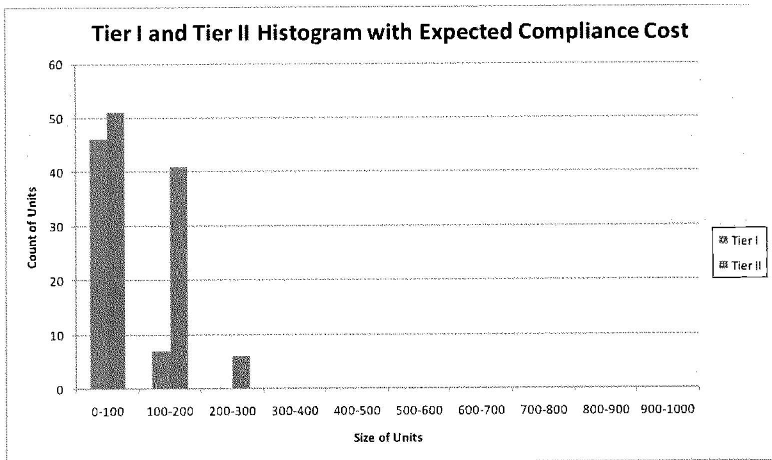


Figure 6-3: Tier I and Tier II Histogram for expected compliance cost application

6.3 General Observations of Sensitivity Screens in Phase I

The sensitivity cases have given information to what variables have impacts on what units are identified as at-risk.

- A greater cost for compliance will result in more coal units to be at risk.
- Lower gas prices result in a greater amount of at-risk coal capacity. This is due to lowered revenue on the system as the clearing energy price for peaking capacity is lower. Higher gas costs provide more revenue on the system for coal units and lower the risk for retirement on the system.
- Carbon costs drive more coal units to be at risk. However, carbon costs combined with higher gas prices could mitigate the amount of at-risk capacity.

7 Phase II

Because EGEAS does not include the detailed transmission system within the modeling capability, it was determined that PROMOD IV® would be utilized to identify if congestion on the transmission system could provide additional revenue to generators to remove them from the list of Tier I and Tier II units identified in Phase I.

7.1 Phase II Assumptions

Four sets of sensitivities were modeled within the PROMOD IV® model, as shown in Table 7-1. These cases represent results from Phase I that maximized and minimized retirements under the MATS only cases and the cases representing a combination of all the studied regulations. The years evaluated included 2016, 2021, and 2026.

Phase II PROMOD IV® Cases
MATS Regulation, Expected Compliance Costs, \$4.50 Gas and \$100 Carbon
MATS Regulation, Expected Compliance Costs, \$10 Gas and \$0 Carbon
Combined Regulations, Expected Compliance Costs, \$4.50 Gas and \$100 Carbon
Combined Regulations, Expected Compliance Costs, \$10 Gas and \$0 Carbon

Table 7-1: Phase II analysis assumptions

Because MISO models the Eastern Interconnect within the PROMOD IV® models, high level EPA evaluation and EGEAS runs had to be made for the entire model footprint. This is done to maintain appropriate cost balances between MISO and the other regions.

Each PROMOD IV® case was run under copper sheet (no transmission limitations) and constrained conditions. The difference between the generation revenue and generation cost for those cases provides the transmission impact on the revenue and cost, or net margin, for each unit on the MISO system. Comparing these results from the Phase I results will show the transmission impact on the Tier I and II list.

7.2 Phase II Results

Phase II results indicate that some of the units on the Tier I and II lists are in locations where greater revenues can be received due to congestion. Of the Tier I units identified in the expected compliance cost set of sensitivities, 12 units amounting to 594 MW result in a positive net margin with the addition of transmission congestion revenue. In Tier II, 28 units amounting to 2,957 MW become profitable.

The congestion revenue information is important because it shows that congestion on the system may provide additional revenue opportunities for some generating units. However, the following Phase III analysis does not include the additional congestion revenue because the revenue number identified is a one year representation from the production cost model runs where the capacity expansion looks at the interaction of retirement and retrofit decisions over a 20 year time frame. Additional analysis will be needed to include a transmission congestion component in the future.

7.3 General Observations of PROMOD IV® Analysis

The Phase II provided analysis shows the following results.

- A total of 3,551 MW could possibly be in transmission sensitive areas.
- Transmission congestion could provide additional revenue that is not captured in the MISO EGEAS analysis of the retirements of at-risk capacity.

8 Phase III

Phase III of the analysis focused on answering the four questions posed at the beginning of the study.

- What are the impacts on capital costs to the system?
- Are there resource adequacy risks?
- What are the impacts on the energy markets?
- Are there transmission adequacy risks?

These questions are answered utilizing four different models. EGEAS was used to evaluate the capital investment costs. These costs include both compliance retrofit costs and replacement capacity costs for retired capacity. The GE-MARS model was used to evaluate the impacts of retirements and retrofits on the Loss of Load Expectation (LOLE) analysis. The PROMOD IV® was used to determine energy cost impacts. Finally, the PSS®E model was used to evaluate transmission system adequacy for the retirement of units on the system.

8.1 Phase III Assumptions

The EGEAS retirement versus retrofit analysis was performed on the case that included expected compliance cost application, a gas cost of $4.50/MMBtu and $0/ton carbon cost. Additionally, increasing levels of carbon costs were also modeled to capture the impacts of the uncertainty of future carbon regulation on the retirement decision.

To perform the EGEAS analysis, two model runs were made for each unit from the expected compliance cost application Tier I and II list. One modeled the unit and its retrofit controls and one modeled the retirement of the unit with replacement capacity. The output with the lowest overall system cost determined the strategy of the unit tested.

The outputs of the EGEAS analysis are passed to the other models. The inputs to those models will include the retirement versus retrofit decision as well as compliance technology impacts and future replacement capacity.

8.2 Phase III Results

The EGEAS analysis identified 46 coal units amounting to 2,919 MW as at-risk units to retire. Increasing the carbon cost increases the amount of retirements of coal units. Figure 8-1 shows the increasing amount of capacity that should be considered for retirement for carbon costs from $0/ton to $50/ton. At the $50/ton cost for carbon, 12,652 MW are at-risk to retire.

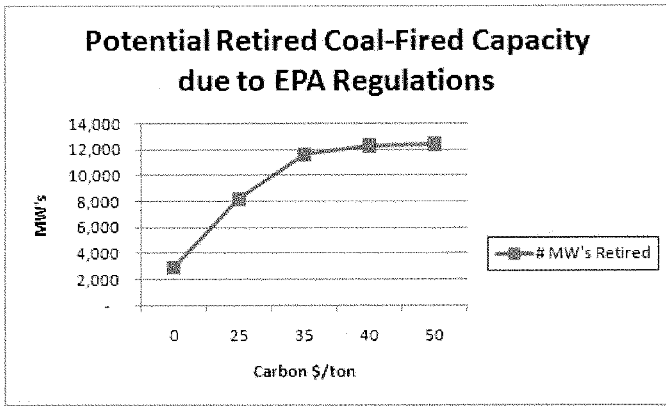


Figure 8-1: Carbon Impacts on Retrofit/Retirement Decision

8.2.1 Capacity Cost Impact

Figure 8-2 demonstrates the 20-year net present value of capital cost impacts of the EPA regulations from the EGEAS modeling runs in 2011 dollars. The comparison of the costs are based on the retirement impacts of 2,919 MW from the non-carbon analysis and 12,652 MW from the carbon analysis compared to the non-carbon, no EPA regulation compliance base case. As can be seen, compliance capital costs are in the range of $22.5 billion to $28.2 billion. Capacity capital fixed charges increases by $1.7 billion to $9.6 billion and Fixed O&M costs range from no increase to $1.1 billion. The total capital cost impacts for compliance with the EPA regulations ranges from $31.0 billion to $32.1 billion.

	No Regulation Case	2,919 MW of Retirements	12,652 MW of Retirements
EPA Compliance Retrofit Capital Costs	$0.0B	$28.2B	$22.5B
New Capacity Capital Fixed Charges	$68.8B	$70.5B	$78.4B
Fixed O&M Costs	$45.7B	$46.8B	$45.7B

Figure 8-2: 20-year NPV capital cost impact of EPA regulations (2011$)

8.2.2 Resource Adequacy Impact

The impact of EPA regulations on the resource adequacy of the MISO system is dependent on the manner in which the system is maintained during the retirement or replacement of affected units. Assuming a controlled replacement of capacity as it is retired, system reliability is actually improved. As the older and less reliable units identified within this study are removed the system average forced outage rate decreases marginally. This decrease in outage rates (less than 1% in both cases) when applied to the entire system results in Planning Reserve Margin decreases of up to 1% from 17.4% with the current system to 16.4% in a system where 12,652 MW of capacity is replaced with system average units.

As an analysis of the base reliability of the MISO system, if all units within the footprint were assumed committed to resource adequacy the Loss of Load Expectation (LOLE) would be roughly 0.088 days/year. If the capacity flagged for retirement in this section was removed and not replaced, the loss of 2,919 MW would decrease the base reliability to the point where the LOLE would be 0.21 days/year, twice the current target of 0.1 days per year or one day in ten years. If all 12,652 MW of capacity were removed from the system and not replaced the resulting LOLE would yield a system with 10 times the probability for outage as the current benchmark or 1.028 days/year.

Removal of capacity without replacement is an unlikely scenario and maintenance of the Planning Reserve Margin is obligated under the MISO tariff. In order to analyze the impacts of a system where the reserve margin was maintained all removed capacity was replaced by theoretical new units which had an outage rate equivalent to the system average after unit removal. In this case when 2,919 MW of capacity was retired and the reserve margin maintained the LOLE improved from the target of 0.1 to 0.093 days/year. When 12,652 MW was retired and replaced in the same fashion the reliability improved even more to 0.068 days/year.

This is indicative of the improved average forced outage rates experienced when less reliable units are removed and replaced with more reliable units. The starting system average forced outage rate was 8.0248% where the removal of 2,919 MW improved average forced outage rate to 7.9983% and 12,652 MW of retirements resulted in a 7.9864%.

As a final analysis of the impact of unit retirement and replacement with system average units a hypothetical reserve margin was established. Since the system average forced outage rates declined after the retirements it can be assumed that Planning Reserve Margins would drop. This was indeed the case as starting from the 17.4% reserve margin established in the base case, 2,919 MW of retirements lowered the reserve margin to 17.2%. Likewise the retirement of 12,652 MW resulted in a decrease in reserve margin to 16.4%. In either case it was assumed that retired units would be replaced by units that matched the system average forced outage rates. The reliability of the system is ultimately dependant on many factors including the availability of the units. If the units identified as at risk for retirement are all replaced with units that have better availability, system reliability will improve.

8.2.3 Energy Cost Impact

The EPA regulations have two primary impacts on the cost of energy on the system. First, all coal units that require retrofits for compliance will have a negative impact on their production of energy. For example, the impacts on heat rates and variable O&M costs will make many units less efficient and more expensive in the production of energy. Second, units that are selected for retirement will remove the lower cost coal capacity from the system and will eventually be replaced by the higher cost natural gas capacity replacement units. This will put a greater dependence on the natural gas units to meet the system energy requirements at higher production costs.

Both identified retirement scenarios were modeled within PROMOD. Figure 8-3 shows that both scenarios increase the average cost of energy on the MISO system. The retirement of 2,919 MW of capacity will result in a slightly less than $1/MWh average cost increase in 2011 dollars. The retirement of 12,652 MW of capacity on the system results in average cost of energy increase near $5/MWh in 2011 dollars.

When carbon costs are added to the cost of energy, the average LMPs on the system increase by approximately $30/MWh. In Figure 8-3, it can be seen that the 2,919 MW of retirement case results in greater energy costs than the 12,652 MW retirement case. This occurs because the higher retirement case was optimized with carbon costs considered and the higher retirements reduce carbon emissions by replacing coal capacity with natural gas capacity.

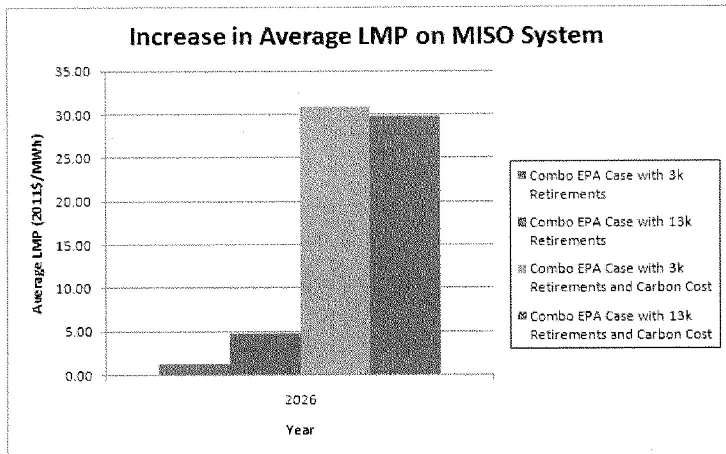


Figure 8-3: MISO Average LMP Impact

8.2.4 Transmission Reliability Cost Impact

Transmission investment that would be needed to meet applicable reliability criteria after the retirement of 2,919 MW and 12,652 MW were studied as two separate scenarios, based on the system configuration in 2015 at summer peak load forecast. Replacement generation dispatch was assumed to be sourced within the MISO footprint.

Transmission investment requirements were minimal in most cases. The total expected transmission investment under the 2,919 MW retirement scenario is $580 million.

The 12,652 MW scenario could require an estimated additional $300 million in transmission upgrades, for a total of about $880 million in transmission investment.

This analysis assumed that none of the retired units that caused transmission problems was replaced with new generation. Although it is a viable option to repower a retirement site, the purpose of this analysis is to identify transmission costs under no replacement.

Potential retirements in neighboring entities that are sufficiently close to MISO to potentially cause reliability impacts were represented in the models. Expected and potential unit retirements in PJM were modeled based on the publically posted PJM unit retirement request list and on application of the EPA impact risk assessment criteria. None of these potential unit retirements impacted expected MISO transmission needs.

9 Conclusion

The proposed EPA regulations will have an impact on the MISO system. It is up to the individual utilities to make the decisions on the retrofit or retirement decision. Many factors will need to be considered for this decision. They will include the cost of retrofit compliance, the cost of replacement capacity to meet resource adequacy requirements and the cost of energy on the system. Asset owners will also consider the cost of needed transmission upgrades, transmission congestion, timelines for compliance, and future regulatory uncertainties such as carbon. MISO addressed these issues, but the results should be considered indicative to what could happen throughout the system. Asset owners will have to take all the aforementioned factors into consideration when making a decision.

This study identified a set of retirements based on a low natural gas price and various levels of carbon costs. Future natural gas prices and carbon price have a direct correlation to the amount of retirements that will occur. Low gas prices encourage retirement of coal units because the replacement energy costs are not significantly higher. However, as gas costs increase, the decision for retirement may become less. Increase of costs for carbon compliance could increase coal unit retirement. Uncertainty around the future economic and regulatory conditions makes the retirement decisions difficult for the asset owners.

This analysis identified impacts on the resource fleet, system energy costs and the transmission system. Under tariff reliability requirements, it is required that the bulk power system will maintain generation and transmission reliability. The EPA regulations add a constraint to the system that must be mitigated. Because of this, the risk of implementing the EPA regulations is not reliability, but the cost to maintain that reliability. Table 9-1 shows those costs identified within the MISO analysis.

	2,919 MW of Retirements	12,652 MW of Retirements
Energy Cost Impacts without Carbon	$1.0/MWh	$5/MWh
Energy Cost Impacts with Carbon	$31.0/MWh	$30/MWh
EPA Compliance Retrofit Capital Costs	$28.2B	$22.5B
New Capacity Capital Fixed Charges	$1.7B	$9.6B
Fixed O&M Capital Costs	$1.1B	$0.0B
Transmission Capital Costs	$0.6B	$0.9B
Total Capital Costs	**$31.6B**	**$33.0B**

Table 9-1: System Costs because of implementation of EPA regulations (2011$)

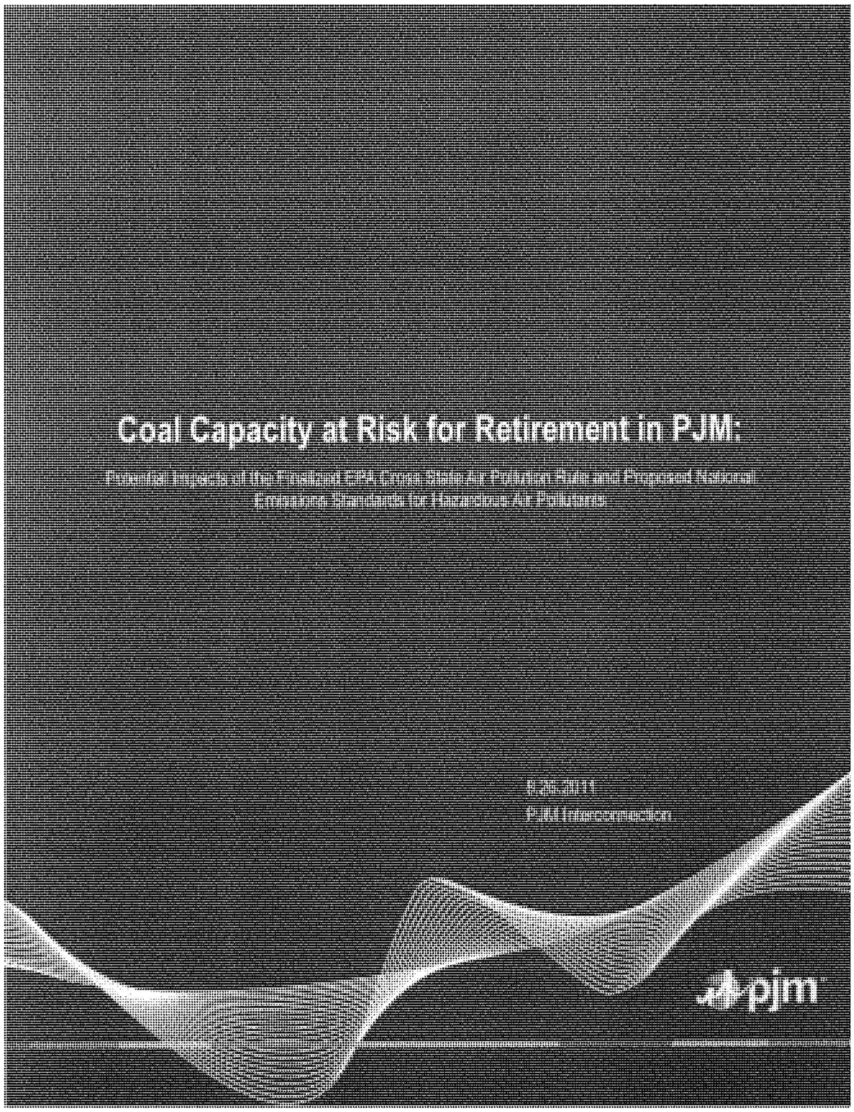
The costs for both sets of retirement scenarios are less than 10% different in this analysis. The primary difference in the outputs is where the costs are allocated. It is difficult to judge which plan is "better." This analysis reviewed the uncertainty around carbon regulation. However, to determine a more likely scenario between the two would require additional iterations of analysis around gas, carbon, and other sensitivity evaluation. The cost of energy within the system contains feedbacks that the models used can't capture. For example, higher dependence on the natural gas fleet could result in higher natural gas prices. At some point, equilibrium will exist at a point with a proper balance of new natural gas resources and gas prices.

10 Next Steps

This analysis did not take into account sensitivities around demand and energy growth or wind penetration. Higher demand and energy growth may result in greater impacts around the cost of system compliance as new resources to replace any retirement selection would impact the system capital investment and energy costs at an earlier time frame. Increase wind resources could suppress energy costs on the system making coal retirements more likely. Both conditions could impact the amount of retirements further.

Additionally, further iterations around the cost of natural gas and carbon need to be evaluated with the identified retirements from this analysis. This would provide additional information on the robustness of the results provided for the uncertainties of what the future may hold for costs on the system.

Finally, this analysis also assumes that the natural gas transmission system is sufficient for the increased dependence on natural gas. This may or may not be true. This question needs to be pursued further to determine if there are costs being left out of the analysis.



Coal Capacity at Risk for Retirement in PJM:

Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants

8.26.2011

PJM Interconnection

pjm

Executive Summary

In its role of maintaining reliability and resource adequacy, PJM has been following the finalized Cross State Air Pollution Rule (CSAPR)[1] and proposed National Emissions Standards for Hazardous Air Pollutants (NESHAP),[2] issued by the United States Environmental Protection Agency (EPA), affecting electric generating units, and coal-fired units in particular. PJM has been in the process of estimating the impacts of these rules on the amount of coal-fired generating capacity that may retire, rather than install pollution control retrofits by examining the retrofit status of coal capacity by the age and size of coal-fired units.

Installation of Pollution Control Retrofits will be Essential to Comply with CSAPR and NESHAP

Compliance with CSAPR and NESHAP will likely require the installation of some combination of the following controls: 1) sulfur dioxide (SO_2) controls such as limestone-based flue gas desulfurization (FGD) or dry sorbent injection (DSI); 2) nitrogen oxide (NO_x) controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR); 3) activated carbon injection (ACI) for mercury; and 4) a fabric filter (also known as a baghouse) for the particulates associated with heavy metals and the use of ACI or DSI.

As of June 30, 2011, there is over 78,000 MW of installed coal capacity in PJM inclusive of the recently integrated ATSI zone and soon to be integrated Duke Ohio and Kentucky (DEOK) zone.[3] Almost 25 percent of coal capacity is in the Mid-Atlantic region (MAAC) of PJM. Table 1-ES shows the total coal capacity in PJM without pollution control retrofits and broken down by region.[4] As much as 37 percent of total coal capacity in PJM may need at least two retrofits that would be required to comply with the combined CSAPR and NESHAP rules.

Table 1-ES: Total Coal Capacity in PJM without Pollution Controls

	PJM RTO	MAAC	Rest of PJM
Total Coal	78,613	18,761	59,852
No SO_2 Controls	30,069	4,281	25,788
No SCR for NO_x Reduction	36,618	8,805	27,813
No Fabric Filter	69,115	13,020	56,095
No SO_2 and No SCR	22,866	2,723	20,143
No SO_2 and No Fabric Filter	29,457	3,756	25,701

Using the same retrofit cost models as used by EPA in its analysis of the CSAPR and NESHAP rules, PJM estimates the average installed costs of these retrofits in PJM to be \$802/kW for an FGD, \$369/kW for an SCR, \$172/kW for ACI and a fabric filter, and \$118/kW for DSI.[5]

Economic Environment Faced by Coal Capacity in Need of Pollution Control Retrofits

Coal-fired generation can cover its going forward costs, inclusive of returns on new investments made in generation plant, through a combination of net energy and ancillary service market revenues and capacity market revenues. Net energy market revenues in particular are driven by electricity demand and the spread between coal and natural gas prices. The economic conditions under which retrofit and retirement decisions are being made include:

- Reduced natural gas/coal price spreads from \$5-\$7/mmBtu in 2006-2008 to \$2-\$3/mmBtu in 2009 that are forecast by the Energy Information Administration to continue until 2016.[6] This reduces the net energy market revenues available to cover the costs of environmental retrofits.

- Lower forecast average hourly energy demand that leads to lower cost resources on the margin setting price and lower net energy market revenues available to cover the costs of environmental retrofits. Moreover, less efficient units will not run as often, further eroding net energy market revenues available to cover retrofit costs.

- Over the past four years, the combination of reduced natural gas/coal price spreads and lower demand have already resulted in lower capacity factors that have fallen from 65 percent in 2007 to about 40 percent in 2010 for coal-fired units less than 400 MW and more than 40 years old.[7] At the same time coal-fired units greater than 400 MW, regardless of age, have maintained relatively constant capacity factors in the face of reduced hourly demands and reduced fuel price spreads.

- Overall, the decline in the gas/coal price spread and average hourly demand have resulted in declining net energy market revenues for all coal capacity, but net revenues remain lowest for coal-fired units less than 400 MW and more than 40 years old.[8]

Physical Screen for Coal-fired Capacity Most at Risk for Retirement in PJM

Coal-fired units more than 40 years old and less than 400 MW are less efficient, run less frequently on average, and accordingly, have seen their capacity factors and net energy revenues decline since 2007. These older, smaller units, therefore, seem likely candidates for retirement should they require substantial environmental retrofits. They also do not enjoy economies of scale in retrofit costs that larger units possess. Therefore, any older, smaller unit in need of at least one major retrofit should be considered at risk for retirement.

Table 2-ES shows the quantity of coal-fired capacity more than 40 years old and less than 400 MW that does not yet have some type of emissions controls.[9] Table 2-ES also shows, in parentheses, the percentage these older, smaller units represent of total coal-fired capacity fitting the emissions control status defined in the far left column. In general, these older, smaller units account for only 29 percent of total coal capacity, but account for more than half of the total coal capacity (in percentage terms) in need of major sulfur dioxide and nitrogen oxide retrofits as shown in Table 2-ES regardless of region. As much as 20,000 MW of coal-fired capacity are at risk for retirement in PJM (inclusive of DEOK and ATSI), with as much as 4,400 MW of that capacity located in the Mid-Atlantic region (MAAC) east of the west-to-east transmission constraints in PJM.

Table 2-ES: Coal-fired Capacity More than 40 Years Old, Less than 400 MW in Size by Control Status and Percentage of Category Total

	PJM	MAAC	Rest of PJM
Total	22,907 (29%)	5,769 (31%)	17,138 (29%)
No SO_2 Controls	17,387 (58%)	2,560 (60%)	14,827 (57%)
No Fabric Filter	20,104 (29%)	3,729 (28%)	16,375 (29%)
No SO_2 Control and No Fabric Filter	16,775 (57%)	2,035 (54%)	14,740 (57%)
No SCR	18,762 (51%)	4,456 (50%)	14,306 (51%)
No SO_2 Control and No SCR	14,541 (63%)	2,236 (82%)	12,305 (61%)

Economic Screen for Coal-fired Capacity at Risk for Retirement in PJM

Using known net energy market revenues from PJM's Energy and Ancillary Service Markets from 2007-2010,[10] PJM has derived the needed additional revenues, expressed in dollars per megawatt-day of installed capacity ($/MW-day ICAP) that generating units would be expected to require to continue operating into the future. PJM estimated retrofit costs from EPA-supplied cost models assuming a 20-year recovery period using the capital recovery factors in the PJM tariff, and estimated tariff-defined avoidable costs for the years 2007-2010.[11] Units in the ATSI and DEOK regions are not included in this analysis because of the lack of PJM-market specific net energy and ancillary service market revenues for these units during 2007-2010. The needed additional revenues are then compared to the Net Cost of New Entry (Net CONE) from the 2014/2015 Base Residual Auction, expressed in installed capacity terms, to determine how many megawatts of coal-fired generation are at risk for retirement.[12]

- Capacity requiring greater than Net CONE are deemed to be "most at risk" for retirement as they could be cost-effectively displaced by the Reference Resource CT that defines Net CONE. If capacity requires more than 1.5 Net CONE, this exceeds the maximum price in RPM.
- Capacity requiring between 0.5 Net CONE and Net CONE are deemed to be "at some risk" and their decisions to go forward will depend upon capacity market prices, all else being equal.
- Capacity requiring less than 0.5 Net CONE are considered "not at risk", and most of this capacity has installed most, if not all, required retrofits required to remain in service.

The 2007-2010 period offers a natural experiment with respect to the impact of natural gas prices on the economic viability of coal units to continue operating into the future. Net energy market revenues in 2007-2008 were high along with natural gas prices. Conversely, net energy market revenues were low in 2009-2010 along with low natural gas prices. Given the forecast of continued low coal-natural gas price spreads and lower forecast average hourly demands into the future, the economic viability of coal units using 2009-2010 net energy and ancillary service market revenues seems to be the most reasonable assumption regarding the future viability of coal-fired generation in PJM under the CSAPR and NESHAP rules.

Table 3-ES: Capacity Economically at Risk for Retirement

Additional Revenue Needed	PJM	MAAC	Rest of PJM
< 0.5 Net CONE	38,234	12,534	25,700
0.5 Net CONE – 1.0 Net CONE	14,147	2,908	11,239
> 1.0 Net CONE	11,051	3,194	7,857

Table 3-ES summarizes PJM's estimate of coal-fired capacity economically at risk. Capacity "most at risk" is shaded in red, capacity "at some risk" is shaded in yellow, and capacity deemed "not at risk" is shaded in green. There is 11,051 MW of coal-fired capacity "most at risk", shaded in red in Table 3-ES, with 3,194 MW in MAAC and 7,857 MW in the remainder of the RTO excluding ATSI and DEOK. Of the capacity "most at risk", the average unit size is less than 200 MW, and the average age is over 50 years old.

There is also another 14,147 MW of capacity "at some risk" for retirement as shown in Table 3-ES and shaded in yellow. The average size is close to 400 MW, and the average age is 37 years old. In contrast, capacity deemed "not at risk" is on average just under 500 MW and 34 years old.

Effects of the EPA Rules Have Already Been Observed in the PJM Market

In the RPM Base Residual Auction (BRA) conducted in May 2011 for the 2014/2015 Delivery Year, the amount of coal capacity cleared was 6,895 MW UCAP lower than what cleared in the BRA conducted in May 2010 for the 2013/2014 Delivery Year, a reduction of 16 percent or about 7,350 MW of installed capacity less.[13] Of the $98.26/MW-day increase in the RTO Locational Deliverability Area (LDA) in the 2015/2015 BRA, PJM has been able to discern the addition of pollution control retrofit costs contributed in approximately $60-$80/MW-day to the price increase.[14]

Additionally, there have been public announcements of the intent to retire an approximately additional 7,000 MW of coal-fired installed capacity by 2015, due to EPA rules, from AEP and Duke that satisfy their resource adequacy requirements outside of the RPM auction construct through the Fixed Resource Requirement (FRR) option.[15] In total, there is over 14,000 MW of installed coal-fired capacity that already appears headed toward retirement largely due to EPA rules. This initial market response to the EPA rules is more than 25 percent greater than the 11,000 MW of capacity requiring more than Net CONE to continue going forward suggesting additional capacity requiring between 0.5 Net CONE and Net CONE may elect to retire rather than retrofit.

Resource Adequacy Does Not Currently Appear at Risk in Spite of Projected Retirements

Even with almost 7,000 MW less coal capacity clearing for the 2014/2015 Delivery Year, PJM estimates the RTO will carry a reserve margin of 19.6 percent for the Delivery Year, including the demand and capacity commitments of FRR entities.[16] Even with the potential retirement of coal capacity already announced by FRR entities, there are also announced commitments to replace a portion of that capacity with new gas-fired capacity such that the RTO would still carry a reserve margin at or above of the target 15.3 percent installed reserve margin. Add into the mix the potential for new entry from Demand Resources, as has been the trend in recent years, and resource adequacy does not appear to be threatened.[17]

Although no system-wide capacity problem is apparent in PJM from the announced retirements, this does not mean that localized reliability concerns may not arise given the location of particular units and the unique locational services they provide such as congestion management of particular transmission facilities, voltage support for the transmission system, or black start services. It is for this reason that PJM proposed, in its comments to the EPA in the NESHAP rulemaking, a "reliability safety valve" to be included in the final EPA NESHAP rule to address these particular circumstances. The key is whether replacement resources or transmission reinforcements can be timely added given the breadth of the potential retirements and the pressure on outside vendors to supply new turbines and related resources.[18]

As long as resource adequacy and local reliability are assured, the cycle of generation retirement and new resource entry are market-driven outcomes that can be reliability and efficiency enhancing. Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus, are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new resources, whether it is new generation, demand response, or energy efficiency, may also provide lower cost alternatives to achieve resource adequacy.

Conclusions and Caveat

- Of the approximately 78,000 MW of coal capacity in PJM, at least 30,000 MW (38 percent) requires sulfur dioxide controls to help comply with both the CSAPR and NESHAP rules.

- Coal units less than 400 MW and more than 40 years old only account for 29 percent of the PJM total (almost 23,000 MW), but account for more than half of the capacity without one or more of the necessary sulfur dioxide or nitrogen oxide retrofits to comply with CSAPR and NESHAP.

- Coal units less than 400 MW and more than 40 years old are less efficient, runs at lower capacity factors, and have the lowest net energy revenues per MW of capacity. As much as 20,000 MW of older, smaller capacity requires at least one major retrofit to comply with the CSAPR and NESHAP rules.

- Approximately 11,000 MW of coal capacity is "at high risk" for retirement because this capacity requires revenues exceeding Net CONE to cover the costs of pollution control retrofits assuming a 20 year cost recovery and gas/coal price spreads that persist as they have over the past two years. An additional 14,000 MW of capacity is "at some risk" as it requires between 0.5 Net CONE and Net CONE to cover the costs of retrofits under the same assumptions.

- In the 2014/2015 RPM BRA, approximately 7,000 MW less coal capacity cleared than in the 2013/2014 BRA and public announcements by FRR entities AEP and Duke indicate the intent to retire approximately 7,000 MW of coal capacity in response to EPA regulations.

One caveat must be kept in mind in considering the range of outcomes discussed in this report. Ultimately, the decision to retrofit or retire a unit will be made by an individual generation owner based on its own needs for cost recovery (e.g. term and internal rate of return), expectations regarding future economic conditions (e.g. gas prices and demand) and the shape of future environmental policy or rules that could affect the electric power industry (e.g. climate change policy).

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3ince the proposal of EPA's Transport Rule in July 2010,[19] PJM has been assessing coal-fired capacity "at risk" for ·etirement due to EPA air pollution control rules. In particular, PJM has focused on the now finalized Transport Rule (now known as the Cross State Air Pollution Rule or CSAPR)[20] and the National Emissions Standards for Hazardous Air Pollutants rule (known as HAP MACT or NESHAP).[21] To date PJM has attempted to identify coal-fired capacity "at risk" for ·etirement based upon the physical unit characteristics such as age, size, relevant pollution controls installed, unit capacity actors, and unit heat rates. Such identification provides a helpful screen to begin to determine the magnitude of units at ·isk for retirement. In addition to updating screens based on physical characteristics, PJM has further refined its assessment by examining the economic viability of coal units to earn sufficient revenues to cover the costs of pollution control retrofits to meet the emissions caps or standards defined by the CSAPR and the NESHAP rule.

However, PJM's analysis is not intended as a substitute for asset owners providing PJM with the earliest possible notice as PJM requested in its comments responding to the proposed NESHAP rule (at least two years before the effective date of the EPA rules) to allow PJM to secure alternative resources or undertake needed transmission upgrades resulting from the unit retirement.[22] Unit retirements are complex decisions based on a number of factors known only to the asset owner. PJM's screen analysis is intended to provide the public with information on the potential magnitude of retirements but not substitute for those unit-specific decisions which well could vary individually and cumulatively from the results of PJM's screen analysis.

Coal capacity accounted for 41 percent of installed capacity and provided of 49 percent of total generation in 2010.[23] Given PJM's responsibility for reliability in terms of facilitating resource adequacy through the Reliability Pricing Model (RPM) Capacity Market, and transmission security through the Regional Transmission Planning (RTEP) Process, it is essential for PJM to begin the process of developing estimates of coal-fired capacity that may retire in response to finalized and proposed EPA regulations. The RPM Capacity Market will send price signals and commit resources on a least-cost basis to achieve resource adequacy so that retirement decisions will be made in the context of those market signals. However, with respect to transmission security, an estimate of specific coal units likely to retire, along with timely actual notice of an asset owner's intentions, can aid PJM in ensuring that appropriate transmission upgrades can be identified and placed into service. This will allow coal-fired capacity to retire as the least-cost compliance option with the EPA rules without harming transmission reliability.

Report Organization

Following this Introductory section, the next section in the report provides an overview of the CSAPR and NESHAP rules which is then followed by an explanation of the types of control technologies that will likely be required to comply with both rules and their respective costs. Next, the report presents an estimation of coal-fired capacity "at risk" for retirement based on the physical characteristics of coal-fired units such as age, size, pollution control status, capacity factor, and heat rate. The estimation based on physical characteristic also alludes to the economics of coal capacity by age and size which is supported by the heat rate and capacity factor information and provides a transition into the economic analysis.

To set the stage for the economic analysis, the next section in the report provides a broad economic context with an emphasis on narrowing coal-natural gas price spreads and the trend in projected lower load growth and ties this back to the historic trends in unit capacity factors and heat rates over time. The next section then provides background information and assumptions used in developing the economic assessment, and is immediately followed the economic estimate of coal-fired capacity at risk for retirement based upon historic net energy and ancillary service market revenues and estimated compliance costs under different scenarios.

The last section summarizes the key conclusions providing bounds for the potential coal-fired capacity at risk of retirement due to the CSAPR and NESHAP rules.

Summary of EPA Air Pollution Rules Analyzed

The United States Environmental Protection Agency (EPA) has in the last year proposed and issued regulations that would require the owners of certain generation resources to make capital investments in air pollution control technologies in order to continue operating the resources. These rules include the Cross-State Air Pollution Rule (CSAPR) issued on July 6, 2011[24] and the National Emission Standards for Hazardous Air Pollutants Rule (NESHAP or HAP MACT) proposed on March 16, 2011[25] (hereto referred to together as the "rules") These rules will impact fossil-fuel-fired generation, primarily coal-fired generation.

Specifically, the CSAPR and NESHAP rules indicate the need for coal-fired generation to install sulfur dioxide (SO_2), mercury (Hg), particulate control, and possibly nitrogen oxide (NO_x) control technologies if they have not already done so. The costs associated with these controls impact the economic viability of generators, which we attempt to analyze in this report. A summary of these rules is provided below.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA introduced a rule to limit the interstate transport of emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) that contribute to harmful levels of fine particle matter (PM2.5) and ozone in downwind states. EPA identified emissions within 27 states in the eastern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS.[26]

EPA also issued a supplemental proposal to request comment on its conclusion that six additional states significantly affect downwind states' ability to attain and maintain compliance with the 1997 ozone NAAQS.[27]

CSAPR was developed to replace the Clean Air Interstate Rule (CAIR), which was remanded by the U.S. Court of Appeals for the District of Columbia Circuit in 2008.[28] The final rule considered comments on the proposed Clean Air Transport Rule, and differs from the proposed rule in a number of areas.[29] This rule does not replace the Title IV "Acid Rain" program for SO_2, which remains intact.[30]

The CSAPR covers all fossil fuel-fired units greater than 25 MW that produce electricity for sale. Cogeneration and solid waste combustion units are exempt for the most part, and the regulation does not allow non-covered units to opt in. All states in PJM's footprint are covered, with the exception of Delaware, and the District of Columbia, which were removed because they did not significantly impact downwind states.[31] The regulation is set to be implemented rather quickly, with Phase 1 starting on January 1, 2012, and Phase 2 beginning January 1, 2014. To facilitate this schedule, the EPA is using Federal Implementation Plans (a federal regulation that the states must follow).[32] The states do have the ability to submit State Implementation Plans (SIPs) to replace the federal plans for compliance beginning in 2013, and, importantly, may propose applicability down to a nameplate capacity of 15 MW.[33]

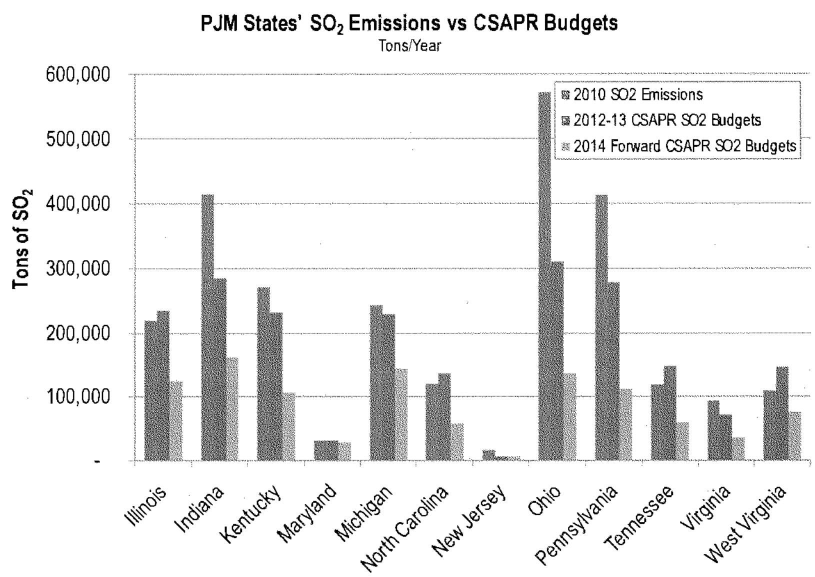
State Emissions Budgets (Allowance Allocations)

CSAPR limits emissions from each state based their contribution to air pollution transport and contribution non-attainment of the fine particulate and ozone NAAQS at assumed cost thresholds reduction SO_2 or NO_x emissions.[34] The rule separates states into two groups for SO_2 reductions based upon their contribution to non-attainment. Group 1 states have larger contributions to non-attainment and therefore have greater SO_2 reductions that must be made by 2014. Group 2 states have smaller contributions and their emissions reductions are not as great as those of Group 1 states.[35] All affected states in PJM are Group 1 states.. CSAPR also separates NO_x emissions into two categories based on Annual and Ozone Season emissions. All affected PJM states are subject to both Annual and Ozone Season NO_x emissions limits.

The CSAPR incorporated updated emissions inventories and revised modeling due to comments received in response to the proposed rule. Incorporated in the final Integrated Planning Model were corrections to the heat rates and emissions rates used for cogeneration units; use of 2009 data for nitrogen oxide emissions rates rather than 2007 data; correction to an out-of-date decision rule for determining nitrogen oxide emissions rates; revised sulfur dioxide removal rates for flue gas desulfurization (FGD) controls based on historical performance data rather than on engineering design data; limitations to unrestricted switching from bituminous to sub-bituminous coal; limitations on short-term coal switching; and corrections to the prices of waste coal.[36] This in turn changed the impact of upwind states on downwind states, and the subsequent allowance allocations (budgets) to affected states. The allocations were also affected by the change in the allocation methodology to heat input-based, which reduced the allocations from the proposal.[37]

Figure 1 shows the 2012-2013 state budgets for SO_2 for affected PJM states alongside 2010 state level emissions in those states.[38] Figure 1 shows Indiana, Ohio, and Pennsylvania require significant emissions reductions (over 100,000 tons each) beginning in 2012-2013. All PJM states affected by the rule will face significant reductions from 2010 levels by 2014.

Figure 1: State Sulfur Dioxide Budgets under CSAPR



Figures 2 and 3 show state budgets for Annual and Ozone Season NO_x emissions alongside 2010 Annual and Ozone Season emissions.[39] Figures 2 and 3 show the amount of required emissions reductions from 2010 levels are much smaller in absolute terms, and in general much more constant over the 2012-2014 period, than the SO_2 reduction levels.

The emissions budgets (allowance allocations) are not set in stone, however. EPA established procedures to update the CSAPR rule after revisions to NAAQS. The next revision due is to the ozone NAAQS, which was expected in July, but was delayed to later this year. The EPA stated in the CSAPR rule that it "anticipates that additional upcoming actions, including likely additional interstate transport reductions to help states attain the upcoming new ozone NAAQS, will result in significant additional nitrogen oxide reductions in the future."[40] EPA also stated that it "is mindful of the need for SIPs to provide for continuing ozone progress to meet the 75 ppb level of the 2008 NAAQS, or possibly lower levels based on the reconsideration."[41] This likely translates to tighter restrictions on nitrogen oxide emissions, a precursor to ozone, which in turn may result in more units requiring selective catalytic reduction, selective non-catalytic reduction or other similarly performing control technology to meet these nitrogen oxide restrictions.

Figure 2: State Annual Nitrogen Oxide Budgets under CSAPR

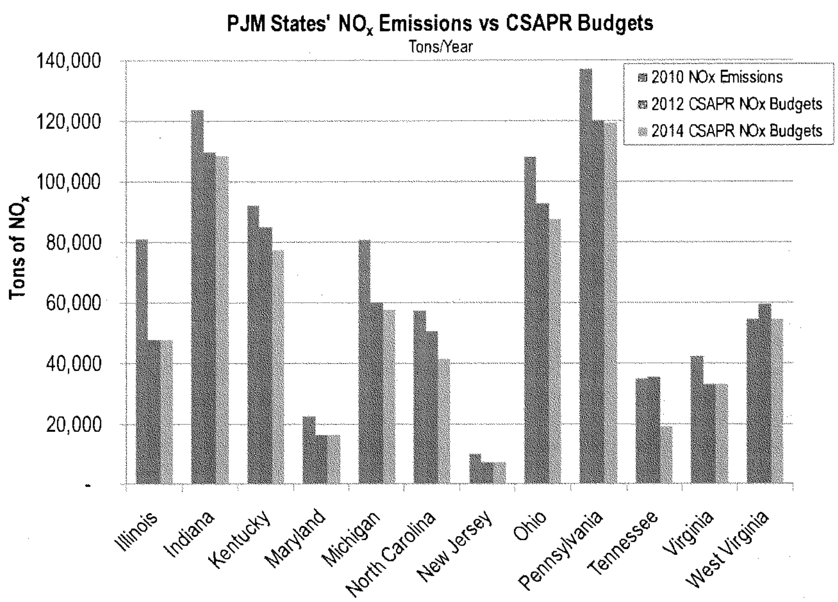
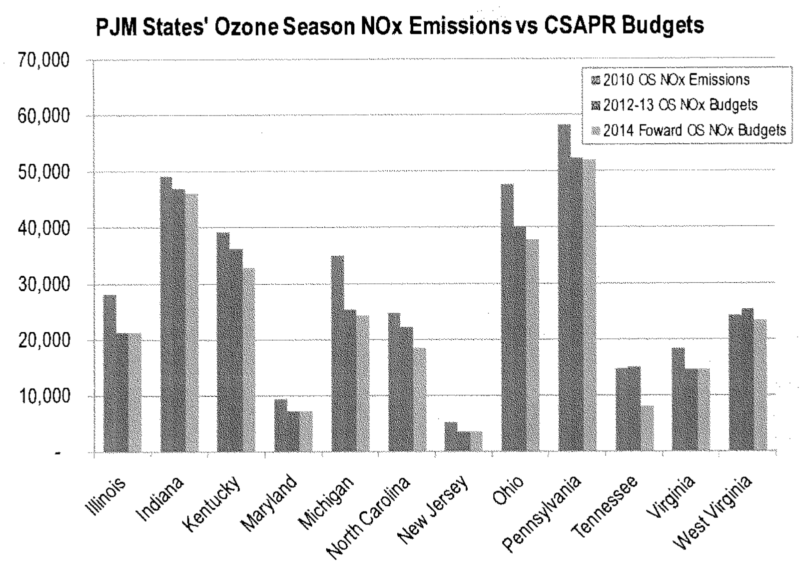


Figure 3: State Nitrogen Oxide Ozone Season Budgets under CSAPR



Emissions Trading

CSAPR creates four **separate** allowance trading programs – Annual NO_X, Ozone Season NO_X, Group 1 SO_2 (a more stringent group comprised of 16 states), and Group 2 SO_2 (a more moderate group comprised of seven states). As such, EPA's state budgets do not utilize CAIR allowances, and in contrast to CAIR, do not allow Title IV SO_2 allowances to be used.[42] Similarly, CSAPR SO_2 allowances will not be valid in the Acid Rain Program.

All allowances are to be allocated to existing and new sources. For the 2012 Federal Implementation Plan there will be potential to auction allowances. For State Implementation Plans beginning in 2013, states may also decide whether to re-allocate allowances among the covered units, allocate to other entities, such as renewable energy facilities, or auction the allowances.[43] Additionally, the EPA modified the rule so that if a unit ceases operations for two years, it will only receive allocations for two years past the two non-operating years, instead of for three years after three non-operating years that was proposed.[44]

CSAPR allows for interstate trading of allowances between sources so long as at the end of the compliance period (calendar year or Ozone Season) emissions do not exceed the overall cap, and for each state, emissions do not exceed the state allowance budget plus a variability limit. The EPA refers to this rule as an "air quality assured trading program".[45] CSAPR defines variability limits, which are a fixed amount of emissions over the state budget that may be emitted each year; however, based on the inherent variability in emissions from electricity generators due to changes in dispatch driven by fuel price differentials or patterns of demand from one year to the next.[46] If the state budget plus the variability limit is exceeded, assurance provisions are triggered. Assurance provisions require covered units in the state that exceeded their budget to submit two allowances for every ton of their share of the emissions exceedance.[47]

National Emission Standards for Hazardous Air Pollutants Rule

On March 16, 2011, the EPA proposed the *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units* also known as the NESHAP Rule. The proposed NESHAP Rule requires coal-fired steam and solid fuel oil (petroleum coke) steam generators to meet an emissions rate standard, based on the maximum achievable control technology (MACT), for mercury, hydrogen chloride (HCl) and total particulate matter (PM), with HCl being a surrogate for all acid gases and PM being a surrogate for non-mercury heavy metals.[48] NESHAP also requires liquid oil fired steam generators to meet limits on total HAP metals (including mercury), HCl and hydrogen fluoride (HF). The proposed rule controls emissions of dioxins/furans and other organic HAPs for all five subcategories through work practice standards rather than emission standards. EPA is proposing numerical emission limits for Hg, particulate matter (PM), HCl, and HF as surrogates for the larger group of hazardous air pollutants that must be controlled under *Clean Air Act § 112(d)*.

Under *Clean Air Act § 112(d)*, existing coal- and oil-fired electric generating units have three years after the proposed *NESHAP Rule* is finalized to comply with the emissions limits. The anticipated compliance deadline is January 1, 2015. An additional (fourth) year to comply may be granted by the local (state) permitting authority effectively pushing the compliance deadline for units granted an extension to January 1, 2016. Because the emissions standards proposed in NESHAP are based on the MACT standard, the rule effectively requires affected generating units to install pollution control technologies in some combination that will result in emissions rates at or below the standards. PJM provided comments to the EPA regarding the compliance timeframe in the proposed NESHAP Rule, and the necessity for the EPA to provide a vehicle for targeted case-by-case compliance extensions where warranted by the time required to address any bulk power grid reliability issues.[49]

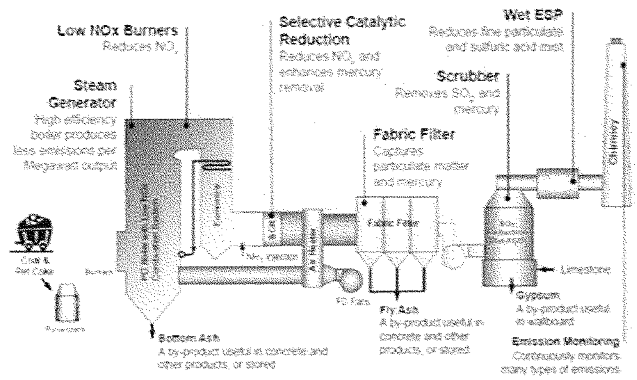
The proposed NESHAP rule employs five subcategories of standards depending upon the characteristics of fuel burned by the affected generating unit, and by combustion technology: one for units firing coal with a heating value ≥ 8,300 Btu/lb, one for units firing coal (lignite) with a heating value < 8,300 Btu/lb), one for units firing liquid oil, one for units firing solid oil-derived fuel, and one for integrated gasification combined-cycle units. Additionally, the proposed NESHAP rule allows emissions averaging among similar units at the same facility, the ability to use surrogates to monitor emissions compliance: hydrogen chloride for acid gases and particulate matter for hazardous metals, the designation of five separate subcategories with tailored limits, and separate monitoring provisions for limited use oil-fired units.

Overview and Costs of Pollution Controls Likely Required for Compliance

Figure 4 provides a graphic overview of the range of pollution control technologies that are likely to be installed in response to the CSAPR and the NESHAP Rule. Many of the pollution control technologies represented in Figure 4 can serve to help coal-fired generation to meet the emissions reduction requirements of both rules. For example, scrubbers, also known as Flue Gas Desulfurization (FGD), can achieve sulfur dioxide removal rates of up to 98 percent, which help reduce sulfur dioxide emissions targeted by the CSAPR.[50] At the same time, FGDs also aid in the removal of acid gases and mercury that is targeted by the NESHAP Rule. Of all the control technologies that coal-fired generation may need to install, FGDs are the most capital intensive as can be seen in Tables 2 and 3 below.[51]

A lower capital cost option to FGDs is known as dry sorbent injection (DSI). While having a lower capital cost (about one-tenth of an FGD at a 500 MW unit size), DSI has higher variable operation and maintenance (VOM) costs as seen in Tables 2 and 3.[52] DSI is not as effective at sulfur dioxide removal, achieving only up to 50 percent removal efficiencies for generally medium to lower sulfur coals.[53] DSI can also be employed to reduce acid gases and mercury under the NESHAP Rule, but would need to be accompanied by the installation of a baghouse in order to meet particulate emission standards that are already in place and to further help reduce mercury emissions.[54]

Figure 4: Representation of Pollution Control Retrofits[55]



Source: Brattle Group

Selective Catalytic Reduction (SCR) as shown in Figure 4 is designed to remove nitrogen oxide emissions that are targeted by the CSAPR. In addition, SCR can provide co-benefits in mercury removal to the extent that if it is paired with an FGD, it should not be necessary to use other controls for mercury removal under the NESHAP Rule.[56] SCRs typically achieve 70-80 percent removal efficiencies for nitrogen oxides.[57]

An alternative to SCR is Selective Non-Catalytic Reduction (SNCR), which has a lower cost than SCR as seen in Tables 2 and 3, but also has lower nitrogen oxide removal efficiencies (typically 25-35 percent).[58] SNCR, unlike SCR, does not have co-benefits with respect to mercury removal.

Finally, a fabric filter (also known as a baghouse), as shown in Figure 1, in combination with activated carbon injection (ACI) can be used to help reduce mercury and other heavy metal emissions from coal-fired generation to meet the requirements of the NESHAP Rule, as well as complement DSI as mentioned above. Fabric filters in combination with ACI have capital costs similar to SCRs as shown in Tables 2 and 3.[59] The ACI cost component is less than one-tenth the cost of the fabric filter.

Table 2: Pollution Control Retrofit Costs for a Representative 500 MW Coal Unit[60]

Control Technology	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
FGD	$501	$8,150	$1.81
DSI	$40	$590	$7.92
SCR	$197	$720	$0.66
SNCR	$19	$260	$1.33
Fabric Filter + ACI	$155+$9	$630+$40	$0.15+$0.93

While Table 2 provides a snapshot of pollution control costs for a representative 500 MW unit, pollution control retrofit capital costs, fixed O&M, and to some extent variable O&M vary with the size of the unit in question. In general, there are economies of scale in retrofit installations, with smaller units facing larger capital costs per kW of capacity, larger fixed O&M costs per MW of capacity, and potentially higher variable costs per MWh of generation output. The implication is that smaller coal-fired units will face greater costs per unit of capacity than larger units that can take advantage of economies of scale in retrofit installation and operation.

Table 3 shows an estimated range of pollution control retrofit costs for coal-fired units in PJM that are derived from cost models developed for the EPA and used in their analyses of the CSAPR and the NESHAP Rule. These cost estimate ranges reflect PJM analysis to determine which pollution control retrofits would be necessary for each coal-fired generator to continue operating while simultaneously complying with the CSAPR and NESHAP rules. Table 3 clearly shows the wide range of costs depending on a unit's size, with the estimates at the higher end of the ranges applying to small units and the lower costs applying to large units.

These higher costs mean that small units will require greater revenues per MW of capacity to pay for pollution control retrofits than will large units. From this fact alone, one may draw the conclusion that smaller coal-fired units in need of major pollution control retrofits will be at greater risk for retirement due the CSAPR and NESHAP rules than will larger units in need of similar retrofits, but which can take advantage of economies of scale. Moreover, given large ranges seen in Table 3, pollution control retrofit costs are unit specific based on size, and no doubt with respect to other factors that only unit owners are aware, making it difficult to draw more specific or definitive retrofit or retire conclusions based on the cost estimates alone. An understanding of the available revenues to cover these costs is also necessary.

Table 3: Pollution Control Retrofit Cost Estimate Ranges for Coal Generation in PJM[61]

Control Technology	MW Size Range	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
FGD Range	28-1,300 MW	$331-$1,149	$1,580-$44,710	$1.01-$3.81
(Average)	(211 MW)	($677)	($12,100)	($1.93)
DSI Range	43 – 1,320 MW	$9-$273	$170-$5,670	$2.00-$15.54
(Average)	(408 MW)	($89)	($1,780)	($5.71)
SCR Range	16 – 554 MW	$175-$427	$550-$15,600	$0.20-$1.41
(Average)	(161 MW)	($263)	($4,130)	($0.47)
SNCR Range	45 – 1,300 MW	$11-$136	$140-$4,900	$0.34-$2.16
(Average)	(256 MW)	($48)	($1,190)	($1.12)
Fabric Filter + ACI Range	16 – 1,320 MW	$118-$468	$520-$9,340	$0.52-$1.59
(Average)	(299 MW)	($225)	($1,990)	($1.09)

In order to place the pollution control retrofit costs in Tables 2 and 3 into context, it is helpful to view them in comparison to the costs to build and operate new natural gas combustion turbines and combined cycle units. In a paradigm in which generation remains traditionally regulated, the cost of building new gas generation would likely be compared to the cost of environmental retrofits to see which is more cost-effective. In a wholesale market environment such as PJM, a comparison of costs of new gas generation to the cost of retrofits provides a market-based benchmark to determine whether retrofitting existing coal-fired generation is cost-competitive with new entry gas resources. Such a market-based benchmark provides some indication of which coal units are at greater risk for retirement if they are not cost competitive with new entry gas resources. Table 4 provides a range of cost estimates for new natural gas simple cycle (no steam generator) combustion turbines and combined cycle (include a heat recovery steam generator) combustion turbines recently developed for PJM and supplemented with information from a recent Energy Information Administration study on the cost of new build generation technologies.[62]

Table 4: Costs of New Entry Natural Gas Technologies

	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
Simple Cycle CT	$665-$975	$6,700-$6,980	$9.87-$14.60
Combined Cycle CT	$1,000-$1,150	$21,600	$3.23

For a representative 500 MW unit with retrofit costs as described in Table 2, it appears that installing an FGD and SCR retrofit that would comply with both CSAPR and the NESHAP rules would be cost competitive with new entry gas technologies on a capital and fixed O&M cost basis alone. For smaller units it is not clear that installing a full suite of retrofits necessary to comply with the CSAPR and the NESHAP rules is cost competitive. For example, it would appear that for smaller units, installing an FGD and SCR is higher cost than a new entry combustion turbine on a capital and fixed O&M cost basis. However, if smaller units could install a different combination of technologies such as DSI, SNCR, and baghouse in combination with ACI, a unit could meet the NESHAP requirements and remain cost competitive with new entry gas generation on a capital and fixed O&M cost basis, but the sulfur dioxide and nitrogen oxide emissions reductions for CSAPR would not be nearly as great, and would leave smaller units more exposed to potentially high allowance prices and by extension higher running costs.

While cost comparisons provide a useful indicator, they are not dispositive. Ultimately, retrofit or retirement decisions will be based on costs, as well as on the potential to earn revenues in wholesale markets in the future. Part of the potential to earn revenues into the future depends upon the overall market environment.

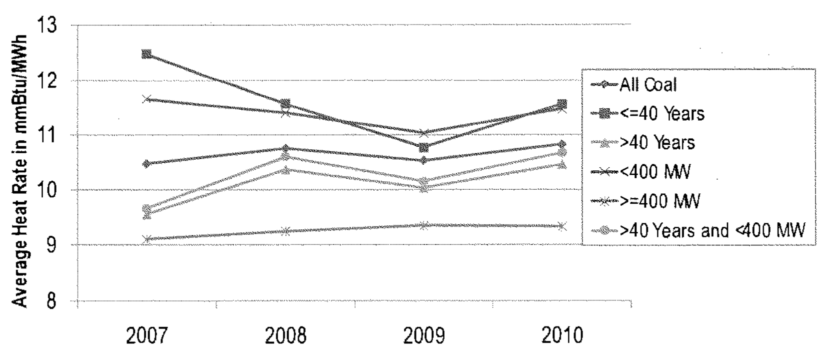
Economic Environment Influencing Retrofit, Repower, and Retirement Decisions

Coal-fired generation can cover its going forward operating costs, inclusive of returns on new investments made in generation plant such as emissions control retrofits, through a combination of net energy and ancillary service market revenues and through capacity market revenues. Net energy market revenues for a coal-fired unit are driven by a combination of three main factors: 1) The efficiency of the unit as measured by its heat rate; 2) the average hourly demand for energy; and 3) the spread between coal and natural gas prices.

Efficiency of Coal Units by Age and Size and the Effect on Net Energy Market Revenues

The efficiency of the coal-fired generating unit determines the order in which it will be dispatched for energy relative to other coal-fired units facing similar fuel prices, and has a bearing on the order in which it will be dispatched relative to other generating units using other fuels, such as natural gas. Units that are more efficient should be dispatched more often, and therefore earn higher net energy and ancillary service market revenues compared to their less efficient counterparts. Those more efficient units then have greater opportunity to cover the cost for pollution control retrofits. Intuitively, one would expect smaller and older generating coal-fired units, all else being equal, to operate at lower efficiencies (higher heat rates) regardless of other market conditions. Figure 5 shows that units in excess of 400 MW in size, regardless of age, operate at lower heat rates (greater efficiency), and are approximately 20 percent more efficient than units less than 400 MW in size regardless of age. Figure 5 also shows that for units more than 40 years old, units less than 400 MW in size are also less efficient than the average for their age class. Overall, smaller and older coal-fired units are likely to be dispatched less often and therefore earn lower net energy and ancillary service market revenues that can be used to cover costs of pollution control retrofits.

Figure 5: Gross Heat Rate of Coal-fired Generation by Age and Size: 2007-2010[63]

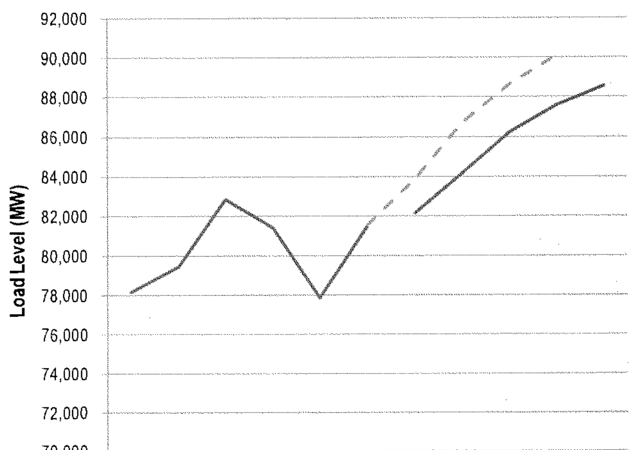


Trends in Average Hourly Demand and the Impact on Net Energy Market Revenues

The average hourly demand for energy is also a driver for net energy and ancillary service market revenues for coal-fired units. The higher the average hourly demand, the more expensive and/or less efficient the marginal unit for energy will be to balance supply and demand on the system, and a higher market clearing price for energy. All else equal, the higher energy demand leads to greater net energy and ancillary service market revenues through higher energy prices. Less efficient coal-fired units benefit from higher demand in that they will be dispatched more often than would be the case with lower average hourly demand, leading to higher net energy and ancillary service market revenues.

For the 2007-2010 period, we can see the declining average hourly demand in 2008 and 2009 due to the recession, and slight bounce back in 2010 as shown in Figure 6.[64] The forecasts for average hourly demand have fallen significantly from 2010 to 2011, showing an average load 2,500 MW lower in each hour in 2014, reflecting the continued expectation of a slow economic recovery. The implication is that if forecasts of average hourly demand remain low, then the expectation is that net energy revenues will be lower in future years for all coal-fired units, all else equal. In addition, this effect is magnified for smaller and older coal-fired units since they will also likely be dispatched less often relative to expectations of higher average hourly demands shown in Figure 6.

Figure 6: PJM Average Hourly Loads: Actual and Forecast



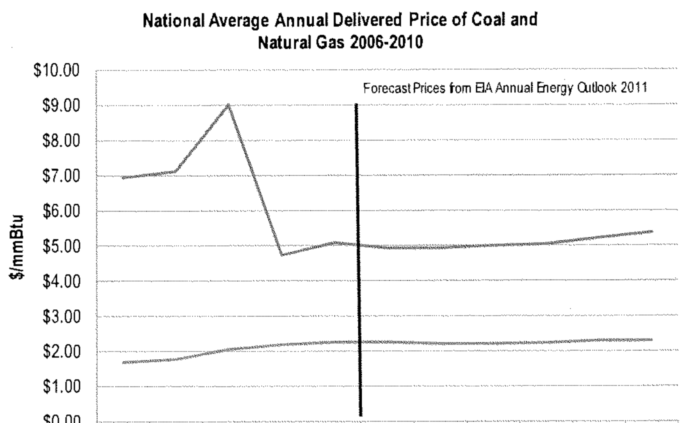
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Actual Average Hourly Load	78,150	79,471	82,857	81,442	77,862	81,510					
2011 Forecast Average Hourly Load							82,167	84,206	86,240	87,596	88,564
2010 Forecast Average Hourly Load						81,557	83,874	86,676	88,632	90,106	

Coal-Natural Gas Price Spreads and the Effect on Net Energy Market Revenues

Net energy and ancillary service market revenues for coal-fired generation will also be affected by the spread between coal and natural gas prices. Historically during peak periods, natural gas fired generation is the marginal unit type dispatched by PJM to balance supply and demand and therefore determines the price of energy during those periods. The higher the gas price, the higher will be energy prices during peak periods, and given the cost of coal, the higher will be net energy market revenues for coal generation. For less efficient coal-fired units, a large coal-natural gas price spread implies they will be dispatched ahead of natural gas generation, whereas a small coal-natural gas price spread may result in combined cycle natural gas generation being dispatched ahead of inefficient coal units given the efficiency advantage of combined cycle gas.

The spread between coal and natural gas prices has fallen significantly, from over \$5.00/mmBtu in 2006-2008 to \$2.50-\$2.80/mmBtu in 2009 and 2010. As forecasted by the Energy Information Administration in its *2011 Annual Energy Outlook* the spread will remain below \$3.00/mmBtu through 2015 as shown in Figure 7.[65] The decreasing coal-natural gas spread means lower net energy market revenues for all coal units, including large, base-load coal units, in every hour they operate. For smaller, older coal units that are less efficient, they may actually be displaced by natural gas units in addition to earning smaller margins when they do operate.

Figure 7: Actual and Forecast Coal-Natural Gas Price Spreads

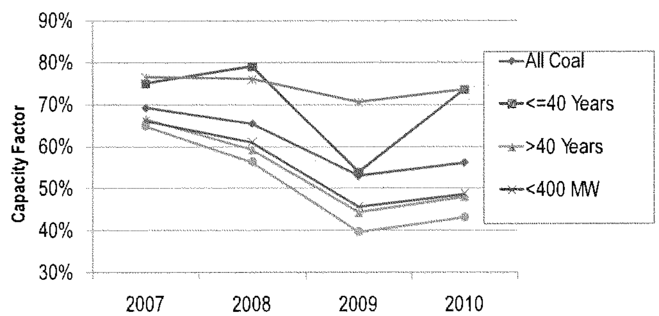


	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gas	\$6.94	\$7.11	\$9.01	\$4.74	\$5.08	\$4.94	\$4.93	\$5.00	\$5.04	\$5.23	\$5.38
Coal	\$1.69	\$1.77	\$2.07	\$2.21	\$2.26	\$2.27	\$2.23	\$2.23	\$2.24	\$2.31	\$2.31

Cumulative Effect on Capacity Factors and Net Energy Market Revenues by Age and Size

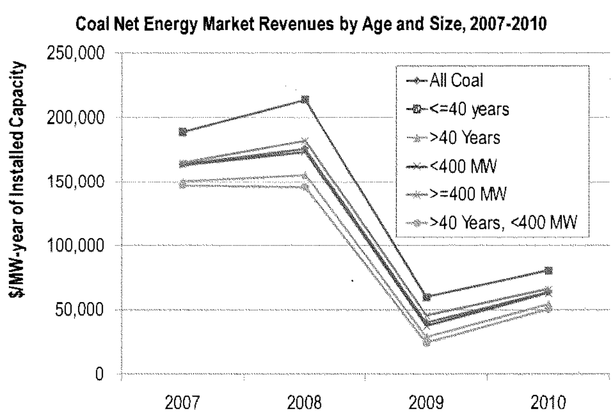
The cumulative effect of the declining average hourly demand and spread in coal and natural gas prices have led to a decline in coal-fired generation capacity factors (units running fewer hours) for smaller and older units that are less efficient as seen in Figure 8.[66] Coal-fired generation that is less than 400 MW in size and more than 40 years old saw its capacity factor decline from approximately 65 percent in 2007 to just over 40 percent in 2010. In stark contrast, units greater than 400 MW in size, regardless of age, saw a relatively small decline in their capacity factors. The reduced average hourly demand and narrowed coal-natural gas price spread has adversely affected the utilization of smaller, older units, which will have a considerable downward impact on net energy and ancillary service market revenues.

Figure 8: Coal Capacity Factors by Age and Size 2007-2010



While larger units have not seen an appreciable erosion in utilization with the changing electricity demand and fuel price conditions, these conditions also have led to declining net energy market revenues based on reduced margins in the hours they do run. Figure 9 shows that all coal units saw a dramatic fall in net energy market revenues for the 2009-2010 period after much higher revenues in 2007-2008 when both average hourly demand fell and the coal-natural gas price spread narrowed. However, Figure 9 shows that larger coal units, greater than 400 MW in size, still held an advantage in terms of net energy market revenues on dollars per MW year basis with 30-50 percent higher net energy market revenues in 2009-2010 compared to coal-fired units that are more than 40 years old and less than 400 MW in size.

Figure 9: Net Energy Market Revenues by Age and Size[67]



Given the recent history of demand and coal-natural gas price spreads, along with forecasts for lower demands than previously expected and the forecast coal-natural gas price spread, the net energy market revenue outlook for older and smaller coal units that continue operating does not appear as attractive as it was during 2007-2008 with higher demands and higher gas prices. The prospects of lower net energy market revenues in the presence of environmental rules that would require significant capital investment will make it more difficult to cover the costs of necessary future environmental retrofits.

Examination of Pollution Controls Currently in Operation as a Screen for Coal-fired Capacity at Risk

As noted in the preceding two sections, smaller, older coal-fired generation is seemingly at greater risk for retirement due to the CSAPR and NESHAP rules than larger units because they are less efficient on average. These units have higher retrofit costs per unit of capacity due to economies of scale, and lower net energy and ancillary service market revenues on average. Coal-fired generating units will only be at risk due to the CSAPR and NESHAP if they do not yet have pollution control technologies installed and in-service , and would have to make capital expenditures to comply with these rules.

Table 5 provides the composition of coal-fired capacity in PJM as of June 30, 2011, inclusive of generation in the recently integrated ATSI zone, the soon to be integrated DEOK (Duke Ohio and Kentucky) zone, and capacity resources external to PJM.[68] These capacity figures do not include 2,799 MW of coal-fired capacity that has already deactivated since January 1, 2009 or has filed to be deactivated by as late as January 1, 2015.

Capacity is broken down by age and size and broad locations reflecting major west-to-east transmission constraints: the Mid-Atlantic region (MAAC) and the rest of the RTO. Table 5 shows there is just over 78,000 MW of summer net dependable coal-fired, installed capacity in PJM. With the focus on smaller and older units "at greatest risk", it is notable that approximately 23,000 MW (29.5 percent) are less than 400 MW in size and more than 40 years old. One-third of coal-fired capacity is less than 400 MW in size regardless of age.

Table 5: Composition of Coal-fired Capacity in PJM by Age, Size, and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	78,613	18,761	59,852
Coal > 40 years	41,815	12,334	29,481
Coal < 400 MW	26,645	7,162	19,483
Coal > 40 years, < 400 MW	22,907	5,769	17,138

The breakdown of capacity by region is such that roughly one-quarter coal-fired capacity is in the Mid-Atlantic (MAAC) and the remainder is in the rest of the RTO. As mentioned previously, PJM expects older and smaller units would likely have greater costs per unit of capacity for emissions control retrofits and consequently would require higher RPM or Energy Market revenues to continue operating. Additionally, uncontrolled units in the MAAC region may have a greater impact on transmission reliability and congestion than in the rest of the RTO, and therefore may warrant additional attention.

The precise number of megawatts requiring emission control retrofits is difficult to identify because CSAPR is a limited cap and trade rule with some flexibility and the NESHAP rule mandates emission rate standards for acid gases, mercury, and non-mercury heavy metals that can potentially be met by different combinations of emissions control technologies. What does seem clear is that some sort of SO_2 and particulate technology would be required to comply with the NESHAP rule that will also provide co-benefits toward meeting the requirements under CSAPR.

Composition of Coal-Fired Capacity without at least One Control Technology

In general, the fewer controls that need to be installed, the lower the costs that must be incurred to comply with the proposed EPA rules if a coal unit wishes to continue operating beyond the proposed NESHAP compliance deadline of January 1, 2015, and be available to operate at high capacity factors under the CSAPR. Table 6 shows the amount of coal-fired capacity without technologies to control sulfur dioxide emissions such as FGD and DSI, or that uses circulating fluidized bed (CFB) combustion technology.[69]

Table 6: Coal-Fired Capacity in PJM without Sulfur Dioxide Controls by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	30,069	4,281	25,788
Coal > 40 years	24,217	3,794	20,423
Coal < 400 MW	17,444	2,617	14,827
Coal > 40 years, < 400 MW	17,387	2,560	14,827

The presence of sulfur dioxide controls, or lack thereof, is indicative of potentially large costs that may need to be incurred by coal-generation to comply with the NESHAP rule for acid gas and mercury reductions, and achieve significant sulfur dioxide reductions that would allow the unit to operate at higher capacity factors under the CSAPR. A total of only 38 percent of coal generation in PJM does not yet have in service some kind of sulfur dioxide control. Yet, nearly 76 percent of smaller, older coal units do not possess any sulfur dioxide controls, and these units account for more than half of the total capacity that does not possess sulfur dioxide controls. By region, MAAC only has 2,500-2,600 MW of smaller, older capacity without sulfur dioxide controls, or 14 percent of the total capacity less than 400 MW and more than 40 years old without sulfur dioxide controls.

In many cases fabric filters appear to be necessary to comply with the NESHAP rule to aid in the control of mercury emissions, or to help offset the increased particulate emissions from the use of ACI for mercury, or DSI for acid gases. Table 7 provides the breakdown of coal-fired capacity that does not have a fabric filter installed.[70] Almost 88 percent of coal-fired capacity does not have a fabric filter installed, with the same percentage of smaller, older units also currently operating without a fabric filter. However, fabric filters appear to be slightly more prevalent in the eastern part of PJM (MAAC) than in the rest of the RTO, with smaller and older units in MAAC accounting for only 18 percent of the total capacity less than 400 MW and more than 40 years old without a fabric filter.

Table 7: Coal-Fired Capacity in PJM without Fabric Filters by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	69,115	13,020	56,095
Coal > 40 years	37,796	9,736	28,060
Coal < 400 MW	21,035	3,786	17,249
Coal > 40 years, < 400 MW	20,104	3,729	16,375

As discussed above, even if coal-fired generators wished to install lower cost sulfur dioxide controls such as DSI, and also install ACI to control mercury, a fabric filter installation would most likely be necessary to achieve the proposed emission rate standards under the NESHAP Rule, while ensuring there was no increase in particulate emissions.[71]

Selective catalytic reduction (SCR) is not essential for complying with the NESHAP rule, but the large reductions in nitrogen oxide emissions allow coal-fired generation to operate at higher capacity factors given the stringent caps under the CSAPR. As mentioned above, an SCR in combination with an FGD can most likely meet the acid gas and mercury emissions standards under the NESHAP Rule without the need to install ACI or a fabric filter. Table 8 shows composition of coal capacity without an SCR installed.[72]

Table 8: Coal-fired Capacity in PJM without Selective Catalytic Reduction by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	36,618	8,805	27,813
Coal > 40 years	26,481	6,905	19,576
Coal < 400 MW	21,818	5,405	16,413
Coal > 40 years, < 400 MW	18,762	4,456	14,306

Only 46 percent of coal-fired capacity across the RTO does not have installed SCR, but for smaller, older units, almost 82 percent doesn't have installed SCR for the control of nitrogen oxides. Of the smaller, older units without SCR, only 24 percent reside in MAAC with the remainder in the rest of the RTO.

Composition of Coal-fired Capacity Lacking More than One Control Technology

Coal-fired generation requiring the installation of more than one of the more expensive pollution control technologies is arguably at greater risk for retirement than requiring the installation of only one technology. For example, while SCR may not be required to comply with the NESHAP Rule, it does provide co-benefits with an FGD for mercury reductions and reduces nitrogen oxide emissions, which are capped under the CSAPR, and should allow the unit to operate more in the energy market, thus earning more revenue to pay for controls. Alternatively, a coal unit may elect to install a combination of DSI and a fabric filter to comply with the NESHAP Rule, and may forego installing an SCR in favor of a lower cost SNCR in the belief that the additional cost of an SCR is more than the revenues it could earn by running additional hours.

Table 9 presents the composition of coal capacity that does not have sulfur dioxide controls ***and*** does not also have a fabric filter.[73] Almost 63 percent of coal capacity within PJM has at least a sulfur dioxide control or a fabric filter, but given the information in Tables 6 and 7, it is most likely the case that a sulfur dioxide control is installed rather than a fabric filter.

Table 9: Coal-Fired Capacity in PJM without Sulfur Dioxide Controls and Fabric Filter by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	29,457	3,756	25,701
Coal > 40 years	23,605	3,269	20,336
Coal < 400 MW	16,832	2,092	14,740
Coal > 40 years, < 400 MW	16,775	2,035	14,740

The set of smaller, older coal units without both controls is smaller than the capacity requiring just one control. However, 96 percent of coal capacity less than 400 MW and more than 40 years old that does not have sulfur dioxide controls also does not have a fabric filter installed. The implication from Table 9 and Table 6 is that almost 17,000 MW of coal capacity that is smaller and older will require multiple pollution control retrofits to comply with the NESHAP rule. The question then remains as to what combination of controls would be installed if these coal units decide to continue operating in compliance with the NESHAP Rule rather than retire, considering the caps on sulfur dioxide emissions under the CSAPR. Without considering controls for nitrogen oxide emissions and the possible co-benefits for mercury reduction, the decision on installing DSI or FGD will rest upon whether the coal unit owner believes the incremental costs of FGD over DSI are less than the additional energy market revenues the unit may earn by being able to further reduce sulfur dioxide emissions to allow it to run profitably in more hours under the CSAPR.

Table 10 shows the coal capacity in PJM that does not have installed both sulfur dioxide controls ***and*** SCR for nitrogen oxide reductions.[74] As has been discussed, the combination of an FGD for sulfur dioxide and SCR for nitrogen oxide reductions would allow a coal unit to run more hours given the caps under CSAPR, while also being able to achieve the emissions rate standards under the NESHAP Rule.

Table 10: Coal-Fired Capacity in PJM without Sulfur Dioxide Controls and SCR by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	22,866	2,723	20,143
Coal > 40 years	17,644	2,236	15,408
Coal < 400 MW	14,598	2,293	12,305
Coal > 40 years, < 400 MW	14,541	2,236	12,305

RTO-wide, only 29 percent of all coal capacity lacks both a sulfur dioxide control and SCR. However, 63 percent of smaller, older units lack both an SCR and some type of sulfur dioxide control. Again, a sulfur dioxide control like an FGD or DSI will be necessary to reduce acid gas emissions targeted under the NESHAP Rule, but an SCR is a control that would allow a unit to run more often under the nitrogen oxide caps of the CSAPR. The decision by unit owners on the combination of controls to install, given a decision to continue operating, will depend upon the unit owner's assessment of what would make the most sense from a financial standpoint.

Assessment of Coal Capacity at Risk Based on Pollution Control Status

Given the economies of scale in the costs of pollution control retrofits, and the historical evidence of lower net energy market revenues for smaller and older units, the need to install any type of pollution control retrofit for these units less than 400 MW and more than 40 years old places such a unit at some risk for retirement. In the class of units less than 400 MW and more than 40 years old, there are at least 20,000 MW lacking a key control (fabric filter) as shown in Table 7. As much as 4,400 MW of that smaller, older capacity located east of the west-to-east transmission constraints in PJM may require some additional retrofit as shown in Table 8.

Still, units that require more than one pollution control retrofit are likely at an even greater risk for retirement because additional controls will increase costs and further diminish the financial viability of continuing in commercial operation beyond January 1, 2015. By this metric, there are nearly 17,000 MW of smaller, older coal units that lack sulfur dioxide controls and a fabric filter.

While an examination of control status by age and size is indicative of the risk of retirement, it is not dispositive as there may be conditions at some of these smaller, older units that PJM cannot observe that would allow the unit to retrofit with a lower cost. For example, a group of small units sharing a common stack could be retrofit more efficiently than the same size units on separate stacks. There may also be conditions at larger units that would make it unattractive or infeasible to install retrofits that cannot be observed by PJM, putting such units at risk for retirement.

Finally, while average cost and revenue trends can be discerned for units of different ages and sizes to provide an intuitive indication of which coal units would be at risk for retirement by control status, the ultimate driver for the retrofit/retirement decision will be the specific economic conditions faced by each unit owner. Such conditions include the location, availability, and unit specific fuel costs in addition to the overall economic environment.

Economic Assessment of Coal Capacity at Risk for Retirement: Setting the Stage

Owners of coal-fired generation subject to the CSAPR and NESHAP rules will only install the necessary pollution control retrofits to continue operating in compliance with the aforementioned rules if they believe they can earn sufficient revenues in the Energy and RPM Capacity Markets in excess of costs (including the costs of retrofits) that will allow them to earn their target return on investment. It is this "simple" decision rule that informs the economic assessment of coal generation that is at risk for retirement. Yet, in spite of the simplicity of the decision rule, the actual inputs into that decision may be far more complex, uncertain, and rely on conditions at units known only to the owners themselves, or on expectations of future operating conditions that are unique to each unit owner.

PJM Evaluation of Pollution Controls Required to Comply with CSAPR and NESHAP

The controls associated with sulfur dioxide and nitrogen oxide reductions required under the CSAPR are well known and understood as discussed above in the section summarizing pollution control technologies. There also is available information on sulfur dioxide and nitrogen oxide emissions levels and rates by which to evaluate the need for control technologies.

From EPA analysis of data provided by generation owners in developing the NESHAP rule, the technologies that can control mercury, acid gases, and non-mercury heavy metals in particulates are also well known and understood. Unfortunately, there is not the same extensive unit level data on hazardous air pollutant emissions by which to evaluate the need for specific control technologies. Consequently, PJM determines the control technologies that will be required based upon data submitted to EPA that were used to determine the NESHAP emissions rate standards.[75] For compliance with

CSAPR, PJM bases retrofits needs on current sulfur dioxide and nitrogen oxide emissions rates compared to a desired emissions rate level that PJM assumes will allow generation resources to achieve compliance with CSAPR in the absence of liquid emissions allowance trading.

Sulfur Dioxide Reductions

The analysis targets a sulfur dioxide emissions rate of 0.15 lbs/mmBtu of heat input.[76] This emissions rate is chosen to achieve sulfur dioxide emissions reductions that would allow a coal unit to continue operating under CSAPR as it would have without CSAPR. Because sulfur dioxide is used as a proxy measure for acid gases, this would also achieve the required acid gas emissions rate standard under NESHAP. The decision rule for sulfur dioxide emissions controls is:

- Install a wet limestone FGD if a sulfur dioxide emission rate reduction of more than 50 percent is required to achieve the target 0.15 lb/mmBtu emissions rate level; or
- Install dry sorbent injection (DSI) if a sulfur dioxide emissions rate reduction of 20-50 percent is required to achieve the target 0.15 lb/mmBtu emissions rate level.

Nitrogen Oxide Reductions

Similar to sulfur dioxide reductions, the analysis targets a nitrogen oxide emissions rate of 0.15 lbs/mmBtu of heat input.[77] This emissions rate would allow a coal unit to continue operating under CSAPR as it would have without CSAPR. The decision rule for nitrogen oxide emissions controls is:

- If an emissions rate reduction of more than 60 percent is required to achieve the 0.15 lbs/mmBtu emissions rate target, an SCR would be installed.
- If an emissions rate reduction of 20-60 percent is required to achieve the 0.15 lbs/mmBtu emissions rate target, an SNCR would be installed.

Mercury Reductions

If a combination of a wet limestone FGD and SCR are installed on a unit, no other controls are assumed to be needed to further reduce mercury or non-mercury heavy metal emissions as the combination of those have been shown to achieve the mercury emissions rate standard. Otherwise, activated carbon injection (ACI) must be installed to control mercury emissions.

Particulates and Non-mercury Heavy Metals

If a unit installs ACI or DSI, then a fabric filter installation will be required even if the unit already has an electrostatic precipitator (ESPs) in service for the control of particulates. A fabric filter ensures the particulates from ACI and DSI bonding to and capturing the hazardous air pollutants are themselves captured and not emitted to the atmosphere.

Factors Influencing the Retrofit/Retirement Decision of Generation Owners

Each generation owner almost certainly has different views regarding the inputs into the retrofit/retirement decision for coal generation impacted by the CSAPR and NESHAP rules. These owner specific beliefs regarding the future profitability of coal units include, but are not limited to the following issues.

- Unit or site specific considerations that are only known to the generation owner. For example, if a unit owner believes there are significant clean-up liabilities once a unit is retired, the owner may choose to install retrofits to continue operating to avoid those liabilities. Conversely, a unit that appears to be financially viable with retrofits may be unable to install them if the site does not have the space to allow for such retrofits except at much higher costs.

- Differing expectation on future environmental policies (e.g. climate change), natural gas prices and average hourly energy demand that will affect future net energy market revenues. Unit owners that are bullish on future market revenues may opt to install retrofits on units that would at first glance appear uneconomic. Along similar lines, some units that appear economic for retrofits may retire if the unit owners are bearish on future energy market prospects.

- Differences in required return on investment and period for retrofit cost recovery. Unit owners willing to recover retrofit costs over longer periods or with lower hurdle rates of return on investment, all else equal, will be more likely to opt for retrofits than for retirement. On the other hand, unit owners with shorter recovery periods and/or higher hurdle rates of return on investment will be more likely to opt for retirement, all else equal, than for the installation of retrofits as the required annual revenue streams to recover retrofits costs will be higher.

- Expectations regarding the extent of new entry of Demand Resources and natural gas technologies as well as growth in peak demand and the cumulative impact on RPM Capacity Market prices. If unit owners believe peak demand growth will recover and growth in new entry will be slow, then RPM revenues are more likely to support retrofits. Conversely, unit owners that believe there will be sluggish growth in peak demand and continued expansion of Demand Resources may opt to retire units if they believe RPM revenues cannot help support retrofit costs.

As part of the economic analysis defined below, PJM has presented different scenarios based on different natural gas price and demand conditions as well as differing time periods for retrofit cost recovery. Other expectations or unit specific considerations are difficult to account for completely as these are only known by the generation owner.

Framework for Analyzing the Economic Viability of Pollution Control Retrofits under the Rules

PJM's analysis of the economic viability of coal-fired capacity to continue operating relies on retrospective data on net energy and ancillary service market revenues from 2007-2010 and detailed cost models of pollution control retrofits used by the EPA in its analysis of the CSAPR and NESHAP rules. It also uses Avoidable Cost Rate (ACR) data from the PJM tariff adjusted using the Handy-Whitman index to derive non-environmental avoidable costs for coal generation during the 2007-2010 period and various capital recovery factors (CRFs) provided for in the PJM Tariff, Attachment DD for differing periods of cost recovery for environmental retrofits.[78]

The PJM analysis determines the cost of pollution control retrofits for a given CRF period (4 years to 20 years), adds in the non-environmental avoidable costs (ACR) defined from the PJM Tariff, and then subtracts the net energy and ancillary service market revenues for the relevant period. The resulting figure is the additional revenue, in the form of capacity payments, necessary for the unit to continue operating in compliance with the CSAPR and NESHAP rules.

Net Energy Market Revenues: Defining Scenarios for Economic Conditions

PJM and the IMM collect the Net Energy and Ancillary Service Revenues from generation owners in conjunction with the market power mitigation procedures for the RPM Capacity Market. The Net Energy and Ancillary Service Market Revenues are used to compute Market Seller Offer Caps in RPM.

As shown above, the 2007-2010 period can be broken up into two distinct scenarios: 1) 2007-2008 when natural gas prices were high, average hourly energy demand was high and consequent net revenues were higher; and 2) 2009-2010 when natural gas prices were low, average hourly energy demand was lower, and consequent net revenues were also lower. A third scenario can be defined as the averaging of the two scenarios over the entire 2007-2010 period.

The retrospective net revenue data therefore provides a natural experiment whereby the outcomes under a high gas price/high demand scenario can be compared to a low gas price/low demand scenario and can be linked to forecasts of future market conditions to draw some tentative conclusion regarding the economic viability of pollution control retrofits under different conditions.

Differing Periods for Capital Recovery Factors

The PJM Tariff, Attachment DD permits units owners to choose the capital recovery factor (CRF) period for the recovery of investments in existing generating units under the Allowance for Project Investment Recovery (APIR) that is a part of the Avoidable Cost Rate (ACR) that goes into determining Market Seller Offer Caps.[79] Given the mandatory nature of the NESHAP rule, generating units that must install emission control technologies may chose to include such costs under the Mandatory CapEx Option which expresses the cost of the retrofits in terms of a four-year recovery period, or units may elect to express these costs under the next highest option for units 25 years and older which allows for the costs to be expressed under a five-year recovery period.[80]

However, unit owners may view the decision to install pollution control retrofits as a much longer term investment and may have expectation of recovering the investment in pollution control retrofits over a longer period such as 10, 15, or even 20 years. The PJM Tariff provides CRF factors for each of these time periods under the assumption of a 10 percent weighted average cost of capital. Because PJM does not know or have access to individual unit owners' hurdle rates for investment, cost of capital, or desired length of time to recover retrofit costs, the PJM analysis calculates retrofit costs for each of the tariff-defined CRFs under each economic scenario discussed above.

Necessary Revenues to Remain Economically Viable

For each combination of economic scenario and CRF employed for each coal-fired unit in PJM, the analysis calculates the necessary revenues that would need to be collected from the RPM Capacity Market, expressed in $/MW-day of installed capacity. The analysis does not seek to compare this number to actual RPM revenues collected during the 2007-2010 period as RPM prices and the associated revenues would not have accounted for the costs of pollution control retrofits associated with the CSAPR and NESHAP rules.

The necessary revenues to be economically viable are more appropriately benchmarked against the Net Cost of New Entry (Net CONE) for a simple cycle natural gas combustion turbine that serves as the Reference Resource in the RPM Capacity Market.

Net CONE as the Benchmark to Define Capacity at Risk for Retirement in the Economic Analysis

Net CONE is defined as the 20-year nominal levelized cost of building a new natural gas combustion turbine less Net Energy and Ancillary Service Market revenues. In the context of the RPM Capacity Market, the Net CONE is the benchmark price of capacity at which PJM would maintain resource adequacy at the peak load plus the Installed Reserve Margin. Consequently, the Net CONE serves as a useful benchmark by which to evaluate the necessary revenues for coal capacity to cover the costs of environmental retrofits, less net energy and ancillary service market revenues. The relevant Net CONE for benchmarking necessary revenues to continue operating would be from the 2014/2015 Base Residual Auction which corresponds to the first year by which coal units must achieve compliance with the NESHAP rule absent any extensions.

For the purposes of categorizing capacity at risk relative to Net CONE, PJM has defined four categories by which to assess the risk of retirement to coal units based on the necessary additional revenues to cover costs relative to Net CONE.

1. ***Necessary revenues greater than 1.5 Net CONE.*** 1.5 Net CONE is the maximum price that could be achieved in any Locational Deliverability Area (LDA) in RPM. If the necessary revenues to cover retrofit costs exceed 1.5 Net CONE, the coal unit would not be economically viable, and not be committed in RPM, even if RPM commits capacity at approximately 3 percent below the peak load plus the installed reserve margin or less. A coal unit in such a position would be "at very high risk" for retirement.

2. ***Necessary revenues greater than or equal to Net CONE,*** but less than or equal to 1.5 Net CONE. In this case new entry natural gas combustion turbine would be more competitive in the RPM Capacity Market than the coal unit requiring retrofits. In the absence of new entry CTs, it is possible for the coal unit to clear the RPM Capacity Market and remain in operation, but the coal unit would still be "at high risk" for retirement because it is not cost competitive with new entry from the Reference Resource.

3. ***Necessary revenues greater than 0.5 Net CONE but less than Net CONE.*** A coal unit in this situation is more cost competitive than a new entry natural gas CT. The determinant of whether a coal unit in this situation clears in RPM and stays in service or retires will depend upon other market dynamics, such as the penetration of demand response, updated load forecasts, expectations about future fuel price and economic conditions. Coal units in this situation are "at risk" for retirement, but the retrofit/retirement decision will depend on a great many variables.

4. ***Necessary revenues less than or equal to 0.5 Net CONE.*** A coal unit in this situation is quite likely to install retrofits and continue operating. Historically in the Mid-Atlantic Region (MAAC), RPM prices have exceeded this value. With the ability of units to include the costs of retrofits in their offers, the price of capacity appears likely to stay above this threshold. In the rest of the RTO, capacity prices have been above and below 0.5 Net CONE. But with the ability to include the costs of environmental retrofits into RPM offers, and the recent 2014/2015 Base Residual Auction, capacity prices are once again approaching 0.5 Net CONE. Coal units in this position are likely "at low risk" for retirement, with any potential retirement decisions based upon factors that PJM cannot observe from the available data.

While there may be other, more granular, benchmark categories relative to Net CONE, the above defined categories can serve as a tool to group coal units in a manner that provides useful information while not being too complicated. However retrofit/retirement decisions eventually made by coal units facing retrofit costs may depend upon factors that cannot be observed from the data by PJM staff.

Economic Assessment of Coal Capacity at Risk for Retirement: Results

Coal Capacity at Risk absent the CSAPR and NESHAP Rules

One question that is certain to arise regarding this analysis is the extent to which lower peak demands, lower overall energy consumption, and lower gas prices would place coal units at risk for retirement even if there were no CSAPR and NESHAP rules. Such a scenario provides a baseline by which to measure the impacts of the rules being analyzed, and provides an indication of how the rules interact with economic conditions in placing coal capacity at risk for retirement.

Figure 10 shows necessary revenues to continue operating by unit size category and by historic gas price/demand scenario. Figure 10 indicates that even under the low gas price scenario using 2009-2010 net revenues, the necessary revenue to continue operating is below $100/MW-day on average for units of different sizes.[81] Whereas under the scenarios that have high gas prices and demand (2007-2008) and the scenario that averages revenues across the entire 2007-2010 period, the necessary revenues to continue operating were negative, meaning coal capacity earned sufficient net revenues from the energy and ancillary service markets to continue operating.

Figures 11 and 12 show the amount of capacity with revenue needs benchmarked against the Net CONE (expressed in installed capacity or ICAP terms) in the MAAC and Rest of RTO regions in PJM.[82] The first thing to notice is there is no capacity that would require more than Net CONE to continue operating regardless of gas price/demand scenario. The second observation is that even in the high gas price/low demand scenario, only about 4,000 MW of capacity would require more than ½ Net CONE to continue forward, with most of that located in the rest of RTO region. The main conclusion from examining the case of no CSAPR or NESHAP rules is that coal capacity would generally not be at risk for retirement due to the recently changed economic environment alone. This is not to say that the changing economic conditions do not have an effect on the economic viability of coal units, but it will be due to the interactions of the changing economic environment with the CSAPR and NESHAP rules.

Figure 10: Necessary Revenue to Continue Operating without CSAPR and NESHAP

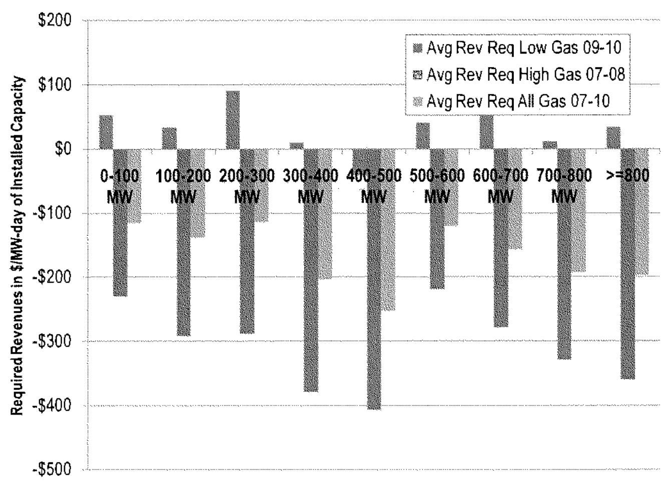
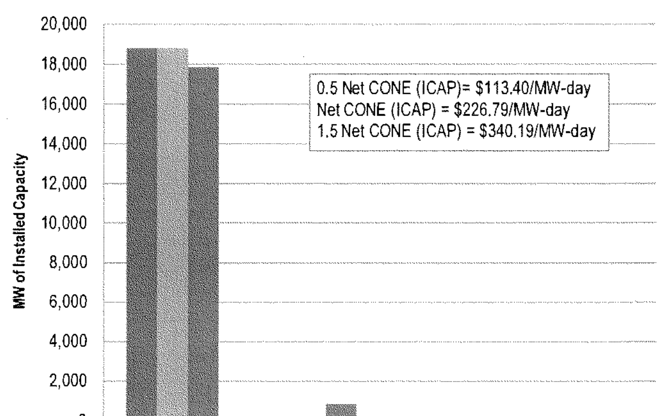
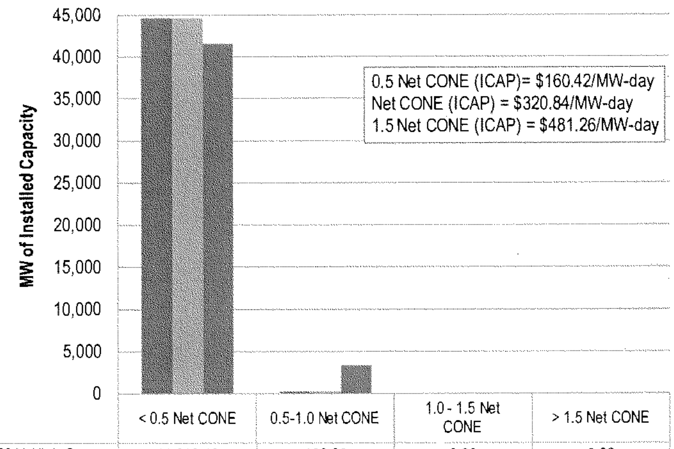


Figure 11: MW of Installed Capacity with Needed Revenues Benchmarked against Net CONE in MAAC



	< 0.5 Net CONE	0.5-1.0 Net CONE	1.0 - 1.5 Net CONE	> 1.5 Net CONE
20 Yr High Gas	18,754.80	0.00	0.00	0.00
20 Yr All Gas 07-10	18,754.80	0.00	0.00	0.00
20 Yr Low Gas	17,861.70	893.10	0.00	0.00

Figure 12: MW of Installed Capacity with Needed Revenues Benchmarked against Net CONE in Rest of RTO



	< 0.5 Net CONE	0.5-1.0 Net CONE	1.0 - 1.5 Net CONE	> 1.5 Net CONE
20 Yr High Gas	44,613.40	183.00	0.00	0.00
20 Yr All Gas 07-10	44,613.40	183.00	0.00	0.00
20 Yr Low Gas	41,512.40	3,284.00	0.00	0.00

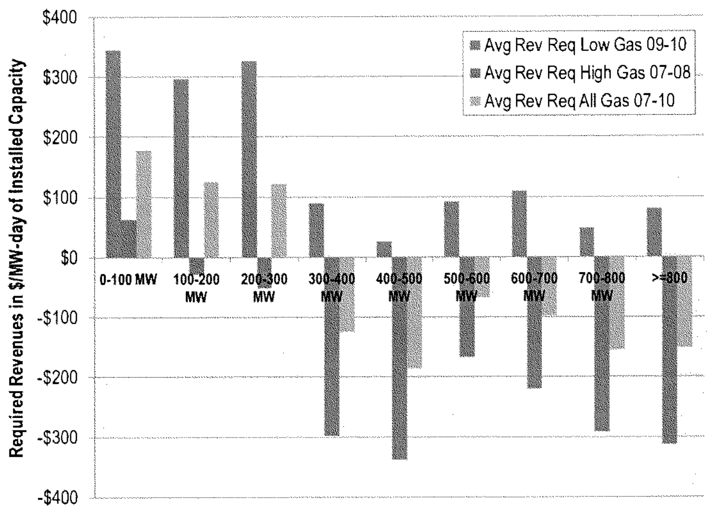
Coal Capacity at Risk Due to the CSAPR and NESHAP Rules

If the owner of a coal unit makes the decision to make investments in pollution control retrofits, it would be reasonable to expect that the unit owner is making a long-term investment in that unit and that the payback period on the retrofit investment would be similar to investing in a new natural gas combined cycle plant or simple cycle combustion turbine. Under the PJM Tariff and market rules this period is 20 years for the new entry reference resource. In thinking about the pollution control retrofit along the same lines as investment in new entry natural gas, it allows for the benchmarking of the costs with retrofits against the Net CONE of the reference resource as discussed above.

In considering future economic conditions, such as gas prices and demand, it is reasonable to use a historic scenario that corresponds as closely as possible to forecasts of future gas prices and energy demand. The required revenues under this scenario would enable retrofit/retire decisions based on forecasts currently in place.

Figure 13 shows the necessary revenues to continue forward for coal units by size and natural gas price/demand scenario. Compared to the results in Figure 10 without CSAPR and NESHAP, the required revenues to continue operating are higher, especially for smaller units. For units below 300 MW in size, the needed revenues are at least $300/MW-day of installed capacity in the high gas price/low demand case, and for all units on average the needed revenues to go forward are greater than zero. Even in the other gas price cases, the economics of smaller units on average have been significantly eroded. This result demonstrates that older, smaller units are less efficient, run less often and will not have the same kind of net revenues to cover retrofit costs, and will also not be able to take advantage of any economies of scale in retrofit installations. For larger units, more than 300 MW in size, the revenues needed to continue operating are generally less than $100/MW-day on average.

Figure 13: Necessary Revenues to Continue Forward by Unit Size and Case



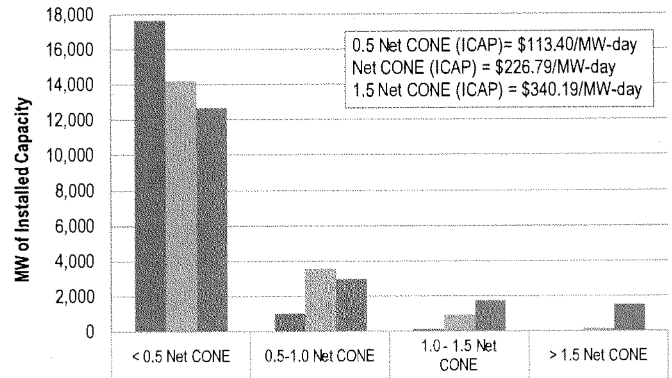
Figures 14 and 15 present the MW quantities of capacity, benchmarked against different levels of Net CONE in MAAC and the rest of RTO. Figure 11 shows that there is about 3,200 MW of installed capacity that requires more than Net CONE to go forward in MAAC under the low gas price/low demand scenario. A total of almost 1,500 MW require more than 1.5 Net CONE, which is the maximum price that could prevail in MAAC if it were a separate LDA. In the rest of RTO, as shown in Figure 15, there is more than 7,800 MW of capacity requiring more than the Net CONE in the low gas price/low demand case. In total across the RTO, there is just over 11,000 MW of capacity that would require more than the Net CONE to continue forward in the low gas price/low demand case. The focus is on the low gas price/low demand case as forecasts of future gas prices and demand are on a much lower trajectory than was otherwise the case just a few years before, and closely match up with gas prices that prevailed in 2009-2010.

Figures 14 and 15 also show capacity revenue needs under the other higher gas price/higher demand cases. If gas prices and demand had remained at 2007-2008 levels, there is slightly less than 1,500 MW of installed capacity that would require more than Net CONE to continue operating. In the case that blends the economic conditions from 2007-2010, this figure would be around 4,300 MW.

Given the baseline considering needed revenues to go forward in the absence of CSAPR and NESHAP, it is clear that these rules are driving the need for increasing revenues to incent coal capacity to continue operating. And the effects of these rules are exacerbated by the low gas price/low demand environment that is forecast to continue.

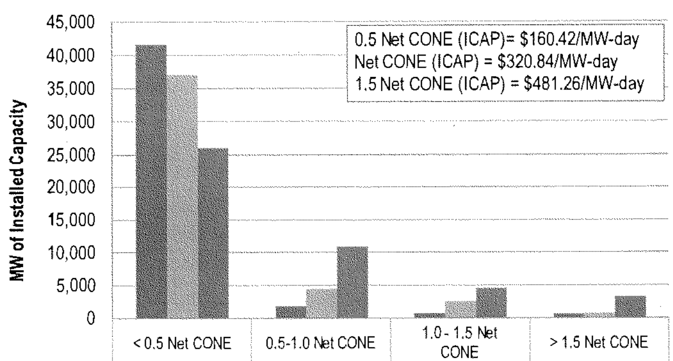
Figures 14 and 15 also show that across the entire PJM footprint, there another approximately 14,000 MW of coal-fired capacity in the low gas price/low demand case that would require between 0.5 Net CONE and Net CONE to continue forward. Coal capacity in this area is at some risk for retirement, but it would be difficult to precisely estimate how much of this capacity would retrofit or retire. As explained above, the retrofit/retirement decision will depend upon factors that cannot be observed by PJM, such as unit specific conditions not immediately available to PJM, and owner expectations about the future economic and policy conditions.

Figure 14: MW of Installed capacity in the MAAC Region by Revenue Needs Relative to Net CONE



	< 0.5 Net CONE	0.5-1.0 Net CONE	1.0 - 1.5 Net CONE	> 1.5 Net CONE
20 Yr High Gas	17,625.70	1,016.10	113.00	0.00
20 Yr All Gas 07-10	14,194.70	3,543.00	888.00	129.10
20 Yr Low Gas	12,634.70	2,926.00	1,705.00	1,489.10

Figure 15: MW of Installed Capacity in the rest of RTO by Revenue Need Relative to Net CONE



	< 0.5 Net CONE	0.5-1.0 Net CONE	1.0 - 1.5 Net CONE	> 1.5 Net CONE
20 Yr High Gas	41,654.40	1,801.00	696.00	645.00
20 Yr All Gas 07-10	37,065.40	4,409.00	2,554.00	768.00
20 Yr Low Gas	26,010.40	10,929.00	4,595.00	3,262.00

Benchmarking PJM's Assessment of Capacity at Risk with Known Market Responses

In the 2014/2015 RPM Base Residual Auction (BRA), there was 6,985 MW of UCAP (unforced capacity), equivalent to approximately 7,350 MW ICAP (installed capacity) less coal-fired capacity that cleared the auction than was the case in the 2013/2014 BRA.[83] Some of this change was due to the cost of environmental retrofits making coal-fired capacity uneconomic relative to lower cost alternative capacity resources, such as demand response, as well as the reduced forecast demand for the 2014/2015 delivery year.[84] Combined there is a RPM Capacity Market response that indicates just over 7,000 MW of installed capacity is likely to retire in response to the CSAPR and NESHAP rules.

In addition to the response in the RPM Capacity Market, there are entities in PJM that satisfy their resource adequacy obligations through the Fixed Resource Requirement (FRR) that allows load serving entities to satisfy their obligations outside of the RPM Capacity Market through their own generation and/or through bilateral contracts with other generation owners. One FRR entity currently in PJM included in the economic analysis, AEP, has publicly announced 6,000 MW of coal retirements. Duke Energy Ohio and Duke Energy Kentucky, to be integrated into PJM at the end of 2011, have announced just over 1,000 MW of coal retirements in response to the CSAPR and NESHAP rules.[85]

The over 14,000 MW that have not cleared in RPM or have publicly announced retirements is consistent with the range coal capacity identified as at risk for retirement from the CSAPR and NESHAP rules in the economic assessment.

Sensitivity of Capacity at Risk to Assumed Payback Periods

The economic assessment of coal capacity "at risk" assumes a 20 year recovery period for retrofit investments along the same lines as the recovery period assumed for the Reference Resource, a natural gas, simple cycle combustion turbine. The choice of 20 year recovery period allow for direct comparability with the cost of the Reference Resource and is a reasonable assumption given that environmental retrofits costs are long-lived investments that will significantly extend the life of a coal unit.

However, the rules governing the RPM Capacity Market in the PJM Tariff allow generation owners to include such investment costs under APIR for recovery for much shorter periods. For example, give the nature of the EPA rules, it is reasonable to assume that generation owners may include retrofit costs under the Mandatory CapEx option and include retrofit costs for a 4 year period as opposed to a 20 year period. This would go into defining the Market Seller Cap for the coal unit, although a unit owner could choose to offer the unit into RPM at a lower price. Generation owners, based on their own expectations and beliefs, may wish to recover the costs of environmental investments over any period between 4 and 20 years as has been discussed previously.

PJM Tariff Attachment DD, Section 6.8 provides for CRFs that correspond to differing recovery periods for capital investment: 20, 15, 10, 5, and 4 years depending on the age of the unit. PJM has used these CRFs to provide sensitivity analysis under the low gas price case to illustrate the effect of shortening the recovery period from 20 years as would be allowed under the PJM Tariff.

Figure 16 shows the effect of moving from a 20 year recovery period to shorter recovery periods down four years recovery period. For recovery periods of 10 years or less, units smaller than 300 MW would need at least the RTO LDA price cap of 1.5 Net CONE or more in order to continue to operate. The net effect of shortening the recovery period generally would be to make retrofitted coal less competitive with new entry gas, and price small units entirely out of the market.

Figure 16: Sensitivity of Needed Revenues to Recovery Period in the Low Gas Price Case

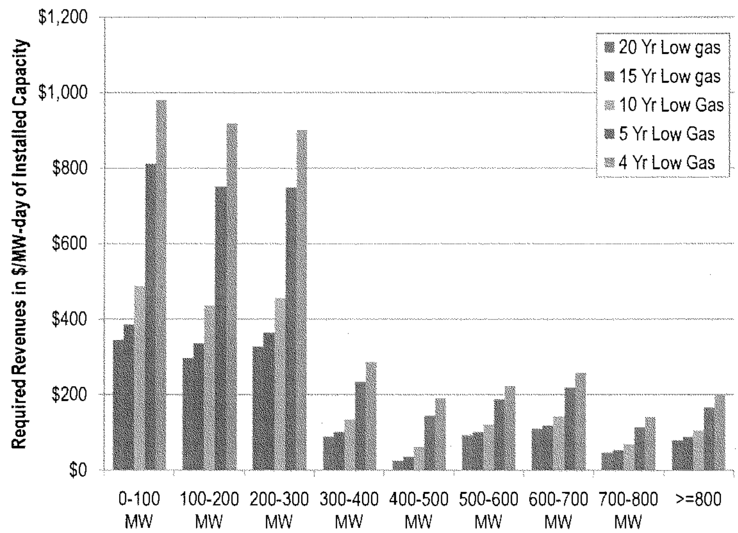
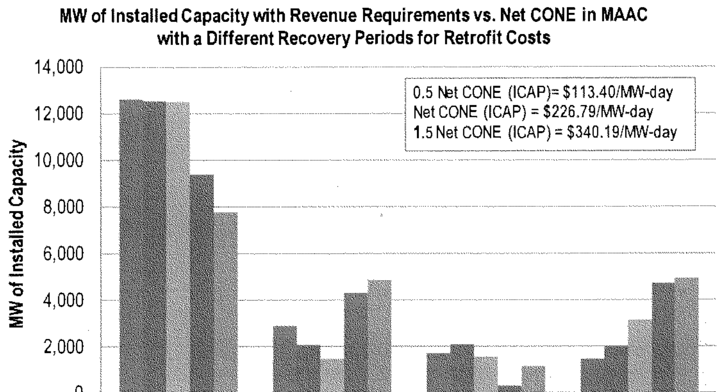


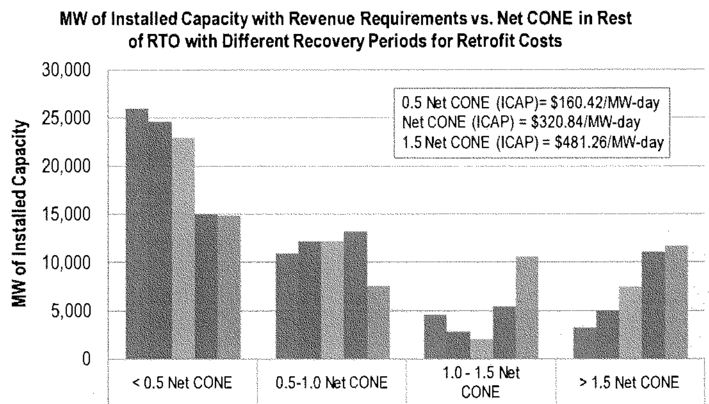
Figure 17: Sensitivity of Capacity Revenue Needs Benchmarked against Net CONE by Recovery Period in MAAC



	< 0.5 Net CONE	0.5-1.0 Net CONE	1.0 - 1.5 Net CONE	> 1.5 Net CONE
20 Yr Low Gas	12,634.70	2,926.00	1,705.00	1,489.10
15 Yr Low Gas	12,549.70	2,073.00	2,122.00	2,010.10
10 Yr Low Gas	12,518.70	1,484.00	1,588.00	3,164.10
5 Yr Low Gas	9,413.70	4,315.00	304.00	4,722.10
4 Yr Low Gas	7,773.70	4,878.00	1,142.00	4,961.10

Figure 17 illustrates the effect of decreasing the cost recovery period in MAAC region. Decreasing the recovery period from 20 years to 4 years results in an almost doubling of capacity requiring more than Net CONE. Figure 18 provides that same information for the Rest of RTO region, except that moving from a 20 year recovery period down to a 4 year recovery period almost triples the amount of capacity that requires more than Net CONE to continue forward.

Figure 18: Sensitivity of Capacity Revenue Needs Benchmarked against Net CONE by Recovery Period in Rest of RTO



	< 0.5 Net CONE	0.5-1.0 Net CONE	1.0 - 1.5 Net CONE	> 1.5 Net CONE
20 Yr Low Gas	26,010.40	10,929.00	4,595.00	3,262.00
15 Yr Low Gas	24,649.40	12,240.00	2,845.00	5,062.00
10 Yr Low Gas	23,023.40	12,220.00	2,080.00	7,473.00
5 Yr Low Gas	14,989.40	13,229.00	5,449.00	11,129.00
4 Yr Low Gas	14,904.40	7,599.00	10,610.00	11,683.00

Conclusions Regarding Coal Capacity Potentially at Risk for Retirement

The CSAPR and NESHAP rules will require coal capacity to make retrofit or retirement decisions that will be implemented in the 2012-2015 period. For example, of the approximately 78,000 MW of coal capacity in PJM at least 30,000 MW (38 percent) requires sulfur dioxide controls to help comply with both the CSAPR and NESHAP rules.

PJM's assessment, based on actual pollution controls installed to date, and physical and operational characteristics of units finds that coal units smaller than 400 MW and more than 40 years old are "at greatest risk for" retirement due to the CSAPR and NESHAP rules. The almost 23,000 MW of capacity smaller than 400 MW and more than 40 years old (29 percent of total PJM coal capacity), generally accounts for more than half of all units that likely require at least one major sulfur dioxide or nitrogen oxide retrofit. As much as 20,000 MW of this smaller, older capacity requires at least one major pollution control retrofit.

Under the assumption of a 20-year recovery of pollution control retrofit investments, and continued low gas prices and lower trajectory of forecast demand, PJM's economic assessment indicates that more than 11,000 MW of coal-fired capacity would require more than Net CONE, or the net cost of a new entry of a simple cycle gas turbine, to continue operating. And of that 11,000 MW, approximately 4,750 MW would need more than 1.5 Net CONE, or the maximum price in an LDA, to continue forward.

In addition, PJM's economic assessment indicates almost 14,000 MW of additional capacity would require between 0.5 Net CONE and Net CONE to continue forward. Benchmarking the economic assessment against market responses to date shows the range of estimates using the physical and economic assessments conducted by PJM are in line with the approximately 7,000 MW of coal that did not clear in the last BRA, but not yet requested deactivation, and the 7,000 MW of announced retirements by FRR entities.

Resource Adequacy is Projected to be Maintained

For the 2014/2015 Delivery Year, PJM estimates that the RTO will carry a reserve margin of 19.6 percent, including the demand and capacity commitments of FRR entities. Even with the potential retirement of coal capacity already announced by FRR entities, there are also announced commitments to replace a portion of that capacity with new gas-fired capacity This means that the RTO would still carry a reserve margin in excess of the target 15.3 percent installed reserve margin. In short, include the potential for new entry from other resources that has occurred in recent years and a system-wide resource adequacy problem does not appear imminent in PJM from the reduction in cleared coal capacity in RPM and from announced retirements.

However, this does not mean that localized reliability concerns may not arise given the location of particular units that may retire and the unique locational services they provide such as congestion management of particular transmission facilities, voltage support for the transmission system, or black start services, as PJM noted in its comments to the EPA in the NESHAP rulemaking.[86] It is for this reason that PJM proposed a "reliability safety valve" to be included in the final EPA NESHAP rule to address these particular circumstances. The key is whether replacement resources or transmission reinforcements can be timely added given the breadth of the potential retirements and the pressure on outside vendors to supply new turbines and related resources.

Resource retirement and new resource entry are part of the natural cycle of any well-functioning and competitive wholesale power market. The cycle of retirement and new entry may also help facilitate major policy changes in a more cost-effective manner. Absent resource adequacy and/or local reliability problems, generation retirements are not, *per se*, an operational negative and may result in enhanced operational reliability and lower costs, taking the public policy context as given.

Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus, are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new entry generation, demand response and energy efficiency resources may also provide lower cost alternatives to achieve resource adequacy and local reliability.

Retrofit, Repower, Retire Decisions Depend on Individual Unit Owner Needs and Expectations

One caveat must be kept in mind in considering the range of coal-fired capacity "at risk" for retirement based upon physical characteristics or based on the economic assessment discussed in this report. The ultimate decision by a generation owner on whether to retire a generating unit or to expend money on required environmental retrofits or repowering to continue operating is based upon owner specific expectations regarding future market conditions or other considerations.. Market conditions can be defined by load growth, coal prices, natural gas prices, future environmental or energy policy, and the mix of generating capacity.

Other owner specific considerations may include, but are not limited to, the willingness to earn lower returns on equity, retirement costs associated with site clean-up, the ability to attract lower cost debt financing than implicitly assumed by economic analysis, potential economies of scale for retrofits on units associated with a common stack, or the willingness to retrofit coal units that may appear marginal as a portfolio hedge against over-dependence on natural gas and possible future natural gas price volatility. While these are all valid considerations that go into the retrofit, repower or retire decision, these considerations constitute private, commercially sensitive information to which PJM does not have access.

Providing Information for PJM Stakeholders and Policymakers

PJM believes the analysis provided in this report will provide information to PJM stakeholders and the PJM stakeholder process that would otherwise not be generally available. Such information may be useful to help guide PJM stakeholders in their discussion of various issues related to market design and transmission planning. The framework for this analysis can serve as a basis for examining other proposed EPA rules and state rules that may result in additional capacity retirements that may not be limited to coal-fired capacity. PJM believes this analysis, and similar subsequent analyses, will provide useful information to market participants and inform the PJM stakeholder process about the impact of forthcoming environmental regulations.

Endnotes

[1] *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone Correction of SIP Approvals*, EPA-HQ-OAR-2009-0491, 76 FR 48208 (Federal Register Vol. 76, No. 152, p. 48208), August 8, 2011 ("Cross State Air Pollution Rule" or "CSAPR"), available at http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf.

[2] *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA-HQ-OAR-2009-0234, 76 FR 24976 (Federal Register Vol. 76, No. 85, p. 24976), May 3, 2011 ("NESHAP" or "HAP MACT"), available at http://www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf

[3] Capacity values are based on summer net dependable capacity or installed capacity in eRPM, and includes resources in the ATSI and DEOK (Duke) zones integrated on June 1, 2011 and January 1, 2012 respectively. For generation in service in PJM as of January 1, 2009, this can be found in PJM's EIA-411 submittal available at http://pjm.com/documents/reports/~/media/documents/reports/2009-pjm-eia-411-data.ashx. For generation coming into PJM as part of the integration of the ATSI Zone, see "ATSI Stakeholder Meeting", October 2, 2009 at 7, available at http://pjm.com/markets-and-operations/market-integration/~/media/committees-groups/stakeholder-meetings/feisg/20091002/20091002-meeting-presentation.ashx. For generation coming into PJM as part of the Duke integration, see "Duke Energy – Ohio, Duke Energy – Kentucky Integration", June 3, 2010, available at http://pjm.com/~/media/committees-groups/committees/mc/20100603/20100603-item-09-duke-energy-integration.ashx. Capacity includes OVEC units at Clifty Creek and Kyger Creek which are co-owned by multiple PJM Members. Finally, the 2008 EIA-860 database, available at http://www.eia.gov/cneaf/electricity/page/eia860.html, was used to confirm capacity values and ownership. This capacity does not include generation resources still in operation, but that have already filed a formal deactivation request to cease commercial operation by January 1, 2015. The list of units deactivated or with pending for deactivation requests are available at http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/generator-deactivations.ashx and http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx.

[4] Pollution control retrofit status as of June 30, 2011. The EPA Clean Air Markets Division maintains and updates the database of generation characteristic including emissions levels, heat input, facility attributes, and gross generation. Information from the database can be customized through and SQL query system. The database is available at http://camddataandmaps.epa.gov/gdm/.

[5] Pollution control retrofits exhibit economies of scale. Smaller units have larger costs per kW of capacity than do larger units. The cost models for pollution control retrofits are available from the EPA as part of its documentation of the Integrated Planning Model used evaluate the impacts of the CSAPR and NESHAP rules. The cost models for FGDs for sulfur dioxide control and SCR and SNCR for nitrogen oxide control are available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html. The cost models for ACI, DSI and fabric filter baghouse are available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html. *See also Infra Notes 51, 52, 56, 58 and 59.*

[6] All prices are delivered prices in nominal dollars. *See* United States Energy Information Administration *Electric Power Monthly*, Table 4-2, available at http://www.eia.gov/cneaf/electricity/epm/epm_sum.html for historical data. For forecast fuel price data, *see* United States Energy Information Administration *Annual Energy Outlook 2011*, Reference Case Tables available at http://www.eia.gov/analysis/projection-data.cfm, Table A13 for natural gas and Table A15 for coal.

[7] *See supra* note 3for data source, and Figure 8.

[8] *See* Figure 9.

[9] *See supra* note 3 *and supra* note 4 for data sources.

[10] PJM staff is grateful to the Monitoring Analytics, the Independent Market Monitor for PJM for providing unit specific Net Energy and Ancillary Service Market Revenues that is used to determine Market Seller Offer Caps in the RPM Capacity Market.

[11] PJM Open Access Transmission Tariff ("PJM Tariff"), Attachment DD, Section 6.7(c) provides technology specific, tariff-defined avoidable cost rates for the 2010/2011 until 2012/2013. These rates were adjusted by the Handy-Whitman Index to determine avoidable cost rates for 2007-2010. Capital recover factors can be found in Attachment DD, Section 6.8(a).

[12] Net CONE for the RTO and MAAC expressed in Unforced Capacity (UCAP) terms can be found at http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/rpm-bra-planning-parameters-2014-2015.ashx. These were then "grossed up" by dividing the Net CONE in UCAP terms by (1-EFORd), where EFORd is the pool-wide average EFORd of 0.0625, to derive the Net CONE in ICAP (Installed Capacity) terms.

[13] "2014/2015 Base Residual Auction Report Addendum" at 1-2, available at http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-rpm-bra-results-report-addendum.ashx.

[14] *Id.* at 2.The RTO LDA price increased from $27.73/MW-day in the 2013/2014 BRA to $125.99/MW-day in the 2014/2015 BRA.

[15] *See* American Electric Power, "AEP Shares Plan for Compliance with Proposed EPA Regulations", June 9, 2011, available at http://www.aep.com/newsroom/newsreleases/?id=1697. In this news release, AEP states that it intends to retire approximately 6,000 MW of coal capacity. *See also* Duke Energy, "Duke Energy Anticipates Ohio Coal Plant Retirement", July 15, 2011, available at http://www.duke-energy.com/news/releases/2011071501.asp. Duke Energy Ohio expresses the intent to retire 862 MW of coal capacity. *See also Duke Energy Kentucky 2011 Integrated Resource Plan* Case No. 2011-00235, June 1, 2011 at 6, available at http://psc.ky.gov/pscscf/2011%20cases/2011-00235/20110701_Duke%20Energy_Application%20and%20Petition.pdf. In its application Duke Energy Kentucky expresses the intent to retire 163 MW of coal capacity. These have not been formally submitted to PJM for deactivation as yet.

[16] "2014/2015 Base Residual Auction Report " at 1, available at http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx.

[17] At the estimated 19.6 percent reserve margin, the RTO has approximately 6,000 MW more installed capacity than is needed to meet the target 15.3 percent installed reserve margin. Duke Energy, as an FRR entity, would need to replace the retired capacity with additional resources to meet its FRR obligation, and it has committed to do so, *See supra* note 15. AEP in its press release expressed the intent to build approximately 1,200 MW of gas fired generation. On net, all other things being equal, the RTO would still be long by about 1,200 MW.

[18] *See* "Corrected Comments of PJM Interconnection, L.L.C." in EPA-HQ-OAR-2009-0234, August 4, 2011, available at http://pjm.com/~/media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234comments.ashx. *See also* "Joint Comments of the Electric Reliability Council of Texas, The Midwest Independent Transmission System Operator, The New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool" in EPA-HQ-OAR-2009-0234, August 4, 2011, available at http://pjm.com/~/media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234-iso-rto.ashx.

[19] *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, EPA-HQ-OAR-2009-0491, (CATR) *Federal Register*, Vol. 75, No. 147, August 2, 2010, pp.45210-45465.

[20] *See supra* note 1.

[21] *See supra* note 2.

[22] *See* "Corrected Comments of PJM Interconnection, L.L.C." in EPA-HQ-OAR-2009-0234, August 4, 2011, at 2-3, available at http://pjm.com/~/media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234comments.ashx.

[23] *See* Monitoring Analytics, LLC, Independent Market Monitor for PJM, *2010 State of the Market Report for PJM*, March 10, 2011, Table 3-42 at 203 and Table 3-43 at 204. This is prior to the integration of Duke and ATSI into PJM.

[24] *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone Correction of SIP Approvals*, EPA-HQ-OAR-2009-0491, 76 FR 48208 (Federal Register Vol. 76, No. 152, p. 48208), August 8, 2011 ("Cross State Air Pollution Rule" or "CSAPR"), available at http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf.

[25] *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA-HQ-OAR-2009-0234, 76 FR 24976 (Federal Register Vol. 76, No. 85, p. 24976), May 3, 2011 ("NESHAP" or "HAP MACT"), available at http://www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf

[26] *See* EPA's Final Rule: *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, EPA–HQ–OAR–2009–0491, 76FR48208 (Federal Register / Vol. 76, No. 152, p. 48208), August 8, 2011 available at http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf

[27] *See* EPA's Supplemental Notice of Proposed Rulemaking: *Federal Implementation Plans for Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin To Reduce Interstate Transport of Ozone*, EPA–HQ–OAR–2009–0491, 76FR40662 (Federal Register / Vol. 76, No. 132, p. 40662), July 11, 2011 available at http://www.gpo.gov/fdsys/pkg/FR-2011-07-11/pdf/2011-17456.pdf

[28] *See* EPA's Final Rule: *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOX SIP Call*, EPA–OAR–2003–0053, 70FR25162 (Federal Register / Vol. 70, No. 91, p. 25162), May 12, 2005 available at http://edocket.access.gpo.gov/2005/pdf/05-5723.pdf

[29] *See* EPA's Proposed Rule: *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, EPA–HQ–OAR–2009–0491, 75FR45210 (Federal Register / Vol. 75, No. 147, p. 45210), August 2, 2010 available at http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1

[30] Any Title IV sources subject to CSAPR provisions will still need to comply separately with all Acid Rain provisions. EPA notes that compliance with CSAPR would reduce SO_2 emissions in covered states substantially below their share of the 2010 Title IV cap. Thus, demand, as well as prices for Title IV allowances, would decrease. EPA states that this could potentially result in emissions increases at sources covered by the Acid Rain Program, but not CSAPR, as Title IV allowances become much less costly than emissions reductions. *See supra* 26, p. 48325, *C. Interactions With Title IV Acid Rain Program*

31 *See supra* note 26, p. 48213-48214, *Executive Summary*

32 CAA section 302(y) defines the term "Federal implementation plan" as "a plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard." *See supra* note 26, p. 48287, footnote 80.

33 "EPA notes that the final Transport Rule allows a state to submit a SIP revision (an abbreviated or full SIP) under which the state may—in addition to making certain types of changes concerning allowance allocations in the Transport Rule trading programs—expand the general applicability provisions of the Transport Rule NOX Ozone Season Trading Program to cover fossil-fuel-fired boilers and combustion turbines serving—at any time starting January 1, 2005 or later— a generator with a nameplate capacity as low as 15 MWe producing power for sale." *See supra* note 26, p. 48274, *VII, B. Applicability*

34 *See supra* note 26, pp.48259-48261. The cost threshold for SO_2 is \$500/ton reduced for 2012-2013 and \$2,300/ton per ton reduced for 2014 and beyond for Group 1 states, and \$500/ton reduced for all years for Group 2 states. The cost threshold for NO_x emissions is \$500/ton reduced.

35 *See supra* note 26, pp.48212-48213. Table III-1 lists the states by group.

36 *See* EPA's *Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule* available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/CSAPR/docs/DocSuppv410_FTransport.pdf

37 "After consideration of all comments, EPA decided to allocate allowances to individual units based on that units' share of the state's historic heat-input, but to ensure that no unit's allocations exceed that unit's historic emissions." *See supra* note 26, p. 48288, *VII.D.1.b. Final FIP Allocation Methodology*

38 *See supra* note 26, Table IV.D-3, pp. 48261-48262 for state SO_2 budgets. See supra note 3 for the source of state level emissions in 2010.

39 *See supra* note 26, Table IV.D.3 and Table IV.D.4, pp. 48261-48263. See supra note 3 for the source of state level emissions in 2010.

40 *See supra* note 26, p. 48349, *XII.J.1.a. Emission Reductions*

41 *See supra* note 26, p. 48219, *IV.C.1.d. Public Comments*

42 *See supra* note 26, p. 48325, *C. Interactions With Title IV Acid Rain Program*

43 "In the state's replacement provisions, the state may allocate allowances to Transport Rule units (whether existing or new units) 121 or other entities (such as renewable energy facilities) or may auction allowances. Additionally, state SIPs can address one or all of the pollutants addressed by the FIPs." *See supra* note 26, p. 48327, *X. Transport Rule State Implementation Plans*

44 "As discussed elsewhere in this preamble, EPA proposed that, if a unit with an existing-unit allocation does not operate for 3 consecutive years, the allowances that would otherwise have been allocated to that unit, starting in the seventh year after the first year of non-operation, would be allocated to the new unit set-aside for the state in which the retired unit is located. EPA is retaining this provision in the final rule but is changing the time of non-operation to 2 years and the time of allowance allocation to a non-operating unit to 4 years. Starting in the fifth year of non-operation, allowances will be allocated to the new unit set-aside for the state in which the non-operating unit is located." See *supra note* 26, p. 48292, *VII.D.2.d. Addition of Allowances to New Unit Set-Asides*

45 *See supra* note 26, pp. 48271-48273 for a description of how this will work in general.

46 *See supra* note 26, pp. 48265-48268. State variability limits are published in Tables VI.F-1, VI.F-2, and VI.F-3, pp. 48269-48270.

47 *See supra* note 26, pp. 48294-48296. The assurance provision allows generating units to group together under a common Designated Representative (DR) so as to pool the risk of allowance surrender under the assurance provision. For example, if a DR has some units with emissions over their allowance allocation and some units under their allocation, on net they may not have exceeded their aggregate allocation they would not be subject to the surrender of two allowances for one ton exceeded. Table VII.E-1, p. 48296 provides an example of how the assurance provision works. The assurance provision effectively limits the amount of interstate trading, thus reducing the cost-effectiveness of the emission trading program under CSAPR relative to the Title IV SO_2 Program and NO_x Budget Programs that allowed unlimited trading.

48 Non-mercury heavy metals include antimony (Sb); arsenic (As); beryllium (Be); cadmium (Cd); chromium (Cr); cobalt (Co); lead (Pb); manganese (Mn); mercury (Hg); nickel (Ni); selenium (Se).

49 *See supra* note 18.

50 *See* the EPA's National Electric Energy Data System (NEEDS) database v.4.10 P_Tox available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/NEEDSv410_PTox.xlsx.

[51] *See* Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Wet FGD Cost Development Methodology,* August 2010, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix51A.pdf, and Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: SDA FGD Cost Development Methodology,* August 2010, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix51B.pdf.

[52] *See* Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Dry Sorbent Injection Cost Development Methodology,* August 2010, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_4.pdf.

[53] *Id.* at 4. If accompanied by a fabric filter baghouse, removal efficiencies are estimated to be as high as 75-80 percent. PJM staff conversations with generation owners place removal efficiencies even lower at around 30 percent.

[54] EPA also evaluated the efficacy for other control technology options including dry sorbent injection (DSI), as potential alternatives for scrubbers and activated carbon injection for mercury control. A dry sorbent is injected into the flue gas ductwork downstream of the boiler where it reacts with the SO_2 and HCl and forms a compound, which is then captured in a downstream fabric filter or ESP and removed as waste.EPA believes that DSI will be an attractive SO_2 and HCl control technology option for smaller and medium sized bituminous coal-fired generating units.

[55] See The Brattle Group, *Potential Coal Plant Retirements Under Emerging Environmental Regulations,* December 8, 2010, available at http://botarobs.com/_documents/UploadLibrary/Upload898.pdf.

[56] *See* Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: SCR Cost Development Methodology,* August 2010, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52A.pdf. EPA believes significant co-benefit air toxics emission reductions will be achieved at existing coal- and oil-fired generating units also subject to the CSAPR with existing or planned retrofits of advanced SCR and flue-gas desulfurization (FGD) pollution control systems for NO_X and SO_2 control, lowering the compliance burden on affected facilities. SCR is considered beneficial to mercury control since it enhances oxidation of elemental mercury, especially from bituminous coals, as the flue gas passes through the catalyst, this ionic mercury is water soluble and susceptible to capture in a downstream FGD control device. *See* NESCAUM, *Control* Technologies *to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants* (March 31, 2011) at 18-19.

[57] *See* the EPA's National Electric Energy Data System (NEEDS) database v.4.10 P_Tox available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/NEEDSv410_PTox.xlsx.

[58] *See* Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: SNCR Cost Development Methodology,* August 2010, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52B.pdf. For the removal efficiency, *see* National Electric Energy Data System (NEEDS) database v.4.10 P_Tox available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/NEEDSv410_PTox.xlsx.

[59] *See* Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Particulate Control Cost Development Methodology,* March 2011, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_5.pdf and *See* Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Mercury Control Cost Development Methodology,* March 2011, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_3.pdf.

[60] *See supra* notes 27, 28, 31, 33, and 34.

[61] *See supra* notes 27, 28, 31, 33, and 34.

[62] *See* United States Energy Information Administration, *Updated Capital Cost Estimates for Electric Generating Plants,* November 2010, available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf. *See also* Pasteris Energy, Inc., *Cost of New Entry Combined Cycle Power Plant Requirements for PJM Interconnection, L.L.C.,* filed in support of *PJM Interconnection, L.L.C.* FERC Docket No. ER11-2875-000, February 11, 2011, available at http://pjm.com/~/media/documents/ferc/2011-filings/20110211-er11-2875-000.ashx. *See also* Pasteris Energy, Inc., *Cost of New Entry Combustion Turbine Power Plant Requirements Additional CONE Area Evaluation for PJM Interconnection, L.L.C.,*, November 16, 2009, available at http://www.pjm.com/~/media/committees-groups/committees/cmec/postings/20091130-cone-ct-revenue-requirements-report.ashx.

[63] *See supra* note 3 for data sources.

[64] The forecast data are for the PJM footprint without the ATSI or DEOK zones to allow for a like comparison across years. *See* PJM Resource Adequacy Department, *PJM Load Forecast Report,* January 2011, available at http://pjm.com/documents/~/media/documents/reports/2011-pjm-load-report.ashx, and the associated data, available at http://pjm.com/documents/~/media/documents/reports/2011-load-report-data.ashx. For the 2010 *see* PJM Resource Adequacy Department, *PJM Load Forecast Report,* January 2010, available at http://pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/~/media/documents/reports/2010-load-forecast-report.ashx.

[65] *See supra* note 6.

[66] *See supra* note 3.

[67] Source of data is PJM Interconnection, L.L.C. and Monitoring Analytics, L.L.C., the Independent Market Monitor for PJM. This data is commercially sensitive and is not publicly available.

[68] *See supra* Note 3 for data sources. The capacity resources external to PJM are majority owned by a group of PJM members.

[69] *See supra* note 3 for data sources.

[70] *See supra* note 3 for data sources. Many units currently control particulate emissions with electrostatic precipitators (ESPs), but would not seem to be sufficient for controlling the additional particulates introduced by ACI and DSI controls, nor do ESPs help in reducing particulate heavy metals as well as a fabric filter baghouse.

[71] "There are various reasons that a combined ACI plus additional baghouse would be required. These include situations where the existing ESP cannot handle the additional particulate load associate with the ACI or where SO3 injection is currently in use to condition the flue gas for the ESP. Another cause for combined ACI and baghouse is use of PRB coal whose combustion produces mostly elemental mercury, not ionic mercury, due to this coal's low chlorine content." *See EPA's Documentation Supplement for EPA Base Case v4.10_PTox – Updates for Proposed Toxics Rules*, p83, Methodology for Obtaining ACI Control Costs available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf

[72] *See supra* note 3 for data sources.

[73] *See supra* note 3 for data sources.

[74] *See supra* note 3 for data sources.

[75] See EPA's List of *facility/unit Hg stack emission averages from the EU MACT ICR Parts II and Part III* available under Utility MACT ICR Data available at http://www.epa.gov/ttn/atw/utility/utilitypg.html

[76] Examination of the unit specific heat input and allowance allocations of sources subject to the SO_2 limits shows that the 2014 cap for all Group 1 and Group 2 states implies an emissions rate of 0.166 lbs SO_2/mmBtu. See *Final CSAPR Unit Level Allocations under the FIP and Underlying Data* available at http://www.epa.gov/crossstaterule/pdfs/UnitLevelAllocData.xls. The target SO_2 emission rates of 0.15 lb/mmbtu for coal and oil, and 0.125 for gas-fired boilers were selected in an attempt to determine the amount of SO_2 reduction, and thus the type of control that would be needed by the steam units to meet proposed CATR and acid gas limits (also keeping in mind that SIPS for the recently revised SO2 NAAQS are being developed). The target is loosely based on the New Jersey mercury limits that included a 0.15 lb/mmbtu limit for boilers beginning in 2012. *See N.J.A.C. 7:27-27 Control and Prohibition of Mercury Emissions, p. 13, Section 7(d)2*, available at http://www.nj.gov/dep/aqm/Sub27.pdf. The Illinois mercury rule established a limit of 0.11 lb/mmbtu for coal boilers. *See* TITLE 35: ENVIRONMENTAL PROTECTION SUBTITLE B: AIR POLLUTION CHAPTER I: POLLUTION CONTROL BOARD SUBCHAPTER c: EMISSION STANDARDS AND LIMITATIONS FOR STATIONARY SOURCES PART 225 CONTROL OF EMISSIONS FROM LARGE COMBUSTION SOURCES Section 225.295 Combined Pollutant Standard: Emissions Standards for NOx and SO2 a) Emissions Standards for NOx and Reporting Requirements, available at http://www.ipcb.state.il.us/documents/dsweb/Get/Document-55740/. SO_2 emission rates of 0.1 appear to be the average low end of the scale for units that are using FGD, with some units having controlled emission rates up around 0.3 lb/mmbtu. Again this number was not an attempt to find the lowest emission rate possible, it was an attempt to define the average emission rate that could be achieved by the fossil fuel-fired boilers employing FGD, so that a choice of FGD or DSI could be distinguished.

[77] Examination of the unit specific heat input and allowance allocations of sources subject to the NO_x limits shows that the 2014 cap for all states implies an emissions rate of 0.09 lbs NO_x/mmBtu. See *Final CSAPR Unit Level Allocations under the FIP and Underlying Data* available at http://www.epa.gov/crossstaterule/pdfs/UnitLevelAllocData.xls. The target emission rates of 0.15 for coal, 0.20 for residual oil, 0.10 for diesel oil, and 0.10 for gas-fired boilers were selected, as well, in an attempt to determine the amount of NO_x reduction, and thus the type of control that would be needed by the steam units to meet the proposed CATR rules (also keeping in mind co-benefits for mercury, and that ozone NAAQS are being revised). The target is based on the NJ HEDD limits for boilers of 1.5 lb/MWh for coal, 2.0 lb/MWh for oil, and 1.0 lb/MWh for gas and diesel beginning in 2015 (1.0 lb/MWh is roughly equivalent to 0.10 lb/mmbtu). *See N.J.A.C. 7:27-19 Control and Prohibition of Air Pollution by Oxides of Nitrogen*, p.27, Table 3, available at http://www.nj.gov/dep/aqm/Sub19.pdf. The Delaware multi-pollutant rule established a limit of 0.125 lb/mmbtu for coal and residual oil boilers. *See TITLE 7 NATURAL RESOURCES & ENVIRONMENTAL CONTROL DELAWARE ADMINISTRATIVE CODE 1146 Electric Generating Unit (EGU) Multi-Pollutant Regulation,* p.3 NO_x Emissions Limitations, available at http://regulations.delaware.gov/AdminCode/title7/1000/1100/1146.pdf. Again this number was not an attempt to find the lowest emission rate possible, it was an attempt to define the average emission rate that could be achieved by the fossil fuel-fired boilers employing SCR, so that a choice of SCR or SNCR could be distinguished, and units with existing controls could determine if they needed to spend money on upgrades.

78 ACR data for the 2010/2011 Delivery Year to the 2012/2013 Delivery Year is available in the PJM Tariff, Attachment DD, Section 6.7(c) for each generating technology categories. Capital Recovery Factors are available in Section 6.8(a) of Attachment DD.

79 PJM Open Access Transmission Tariff (PJM Tariff), Attachment DD, Section 6.8.

80 *Id.*

81 Even in the absence of pollution control retrofit costs, there are still additional costs, ACR-related costs defined in the PJM Tariff in Attachment DD, Section 6.8(a) that would need to be covered by additional revenues.

82 *See supra* note 12.

83 *See supra* note 13.

84 In addition there is close to another 1,000 MW of coal-fired capacity that has not cleared in the past two consecutive BRAs where it is not clear if the units will retire.

85 *See supra* note 15.

86 *See supra* note 18.

Mr. WHITFIELD. Thank you.

Ms. LaFleur, you are recognized for 5 minutes.

STATEMENT OF CHERYL A. LAFLEUR

Ms. LAFLEUR. Thank you very much, Mr. Chairman, Ranking Member Rush and members of the subcommittee. I also very much appreciate the opportunity to testify today.

My name is Cheryl LaFleur. In July 2010, I was confirmed as a commissioner of the Federal Energy Regulatory Commission. In my past career, I had the privilege of serving electric and natural gas customers in New England and New York. That experience taught me firsthand how important electric reliability is to real people and real communities. Since joining the Commission a little over a year ago, I've made reliability one of my top priorities.

For some time now, we have been hearing about the EPA's proposed air and water regulations and their potential to affect our energy supply. Although not all of the regulations are final, I believe it is important to consider them as a package when assessing their potential affect on reliability. This is because the owner of a power plant will appropriately consider all of its EPA regulations, among other factors, in determining whether it is economically feasible to retrofit or repower a unit or whether it makes economic sense to retire the unit.

Should the owner of a power plant decide to retire a unit because the unit cannot be economically retrofitted to meet the new EPA regulations, it must notify the State and regional planning authorities of its decision. Those authorities must then determine whether there is enough available generation or transmission to allow the unit to retire without affecting reliability or whether the retirement will create the need for new generation, new transmission or other resources in order to maintain reliability. Like an owner's decision whether to retrofit a replace a unit, the reliability consequences of a retirement will be dependent on the specific facts of each case, each locality and each region.

While the EPA regulations are not expected to affect our overall resource adequacy as a Nation, they may be present reliability issues in particular localities or regions. In some regions, conditions may be such that a retirement or several retirements related to the new regulations will not create a reliability concern. In other areas, the retirement of even a single unit may create the need for an alternative. In this regard, I believe that for studies about the potential effects of the EPA regulations to have the most accuracy and predictive value, they must be conducted after the regulations are final and unit owners have decided whether to retrofit or retire. Studies under these conditions don't necessarily require the extensive number of assumptions required for nationwide analysis that are driving all the different numbers we have now and are more likely to really drill down on the local and regional issues that we really need to face.

If a retirement does create a potential reliability issue, the owners and the planning authorities must determine what resources will replace the unit and how long it will take to bring the new resources online. Given the long lead time for certain types of resources, there may be a gap of time when a replacement facility is not yet available but the retiring unit is no longer compliant with the new regulations. In such cases, a time-limited waiver of EPA regulations may be needed. In other cases, a reliability must-run contract under the authority of the Commission may also be needed to allow the power plant to operate within certain discrete parameters for a defined period of time.

I believe that any waivers or flexible solutions must be targeted and discrete. Specific reliability analyses at the local and regional level are much more meaningful than all the nationwide estimates that are floating around. The circumstances of each retirement and the need for replacement are fact-specific. I do not support a blanket delay of EPA regulations but I will certainly champion specific extensions where needed for reliability. I believe that the EPA should and that the EPA does understand the need to be flexible in specific cases.

Because of our jurisdiction over regional transmission, utility rates and reliability standards, FERC should be actively involved in these issues when they arise. I believe we can play an important role in discussions among regional planners, NERC and the regional reliability entities, utilities, States and the EPA. I think it would helpful for FERC to sponsor a workshop or series of workshops that bring together all these stakeholders to discuss the regulations, as Commissioner Norris said, the tools we have at our disposal to meet them. For example, FERC can examine and approve market rules designed to facilitate reliability and designed to increase the notice that planners get when retirements are happening. I am confident that we as a Nation can ensure that the EPA's proposed air and water regulations do not adversely affect reliability provided there is coordination and flexibility in their implementation.

Thank you.

[The prepared statement of Ms. LaFleur follows:]

Summary of Testimony of Commissioner Cheryl A. LaFleur
Federal Energy Regulatory Commission
Before the House Subcommittee on Energy and Power
Of the Committee on Energy and Commerce
United States House of Representatives

September 14, 2011

Chairman Whitfield, Ranking Member Rush, and members of the Subcommittee, here is a summary of my testimony, as well as a copy of my written testimony.

I believe that it is important to consider the EPA regulations as a package when assessing their potential effect on reliability, because the owner of a power plant will appropriately consider all of its EPA compliance obligations in determining whether it is economically feasible to retrofit or repower a unit, or to retire the unit. This decision will be specific to the facts of each unit. The reliability consequences of a retirement also will be dependent on the specific facts of each case.

I do not think that the proposed EPA regulations will imperil the overall resource adequacy of the United States grid (I believe that all of the studies on this issue have already been sent to the Committee). I note that the regulations may present regional and local reliability challenges that will require state and regional planners as well as plant owners to use the tools at their disposal to respond.

If a retirement does create a potential reliability issue, the unit owners, in conjunction with state and regional planning authorities, must determine what resources will replace the unit, how long it will take to bring the replacement resources into service, and what to do in the interim. Once the local reliability considerations of a particular unit's retirement are known, there will need to be flexibility in specific cases. I believe that any waivers or flexible solutions must be targeted and discrete, since the circumstances of each retirement and need for replacement facilities are fact-specific. I do not personally support a blanket delay of EPA regulations, but will certainly champion specific extensions where needed for reliability.

Because of our jurisdiction over regional transmission planning, utility rates, and reliability standards, FERC should be actively involved in these issues when they arise. I believe that FERC can play an important role in discussions among regional planning authorities, regional reliability entities, the North American Electric Reliability Corporation, utilities, states, and the EPA. For example, FERC could sponsor a workshop (or series of workshops) that bring together states, utilities, regional authorities, and other stakeholders to discuss the impacts of the EPA regulations and assess what tools we collectively have at our disposal.

I believe that we as a nation can ensure that the EPA's proposed air and water regulations do not adversely affect reliability, provided we ensure that there is coordination and flexibility in their implementation.

Testimony of Commissioner Cheryl A. LaFleur
Federal Energy Regulatory Commission
Before the House Subcommittee on Energy and Power
Of the Committee on Energy and Commerce
United States House of Representatives

September 14, 2011

Chairman Whitfield, Ranking Member Rush, and members of the Subcommittee:

Thank you for the opportunity to testify.

My name is Cheryl LaFleur, and in July 2010, I was confirmed as a Commissioner of the Federal Energy Regulatory Commission. In my past career, I had the privilege of serving electric and natural gas customers in New England and New York. That experience taught me firsthand just how important electric reliability is to real people and real communities. Since joining the Commission a little over a year ago, I have made reliability one of my top priorities. I appreciate the opportunity today to discuss the potential impact the EPA's regulations may have on electric reliability.

For some time now, we have been hearing about the EPA's proposed air and water regulations and their potential to affect our energy supply. Although not all of these regulations are final, I believe it is important to consider them as a package when assessing their potential effect on reliability. This is because the owner of a power plant will appropriately consider all of its EPA compliance obligations, among other factors, in determining whether it is economically feasible to retrofit or repower a unit, or whether it makes economic sense to retire the unit.

The decision to retrofit or retire is dependent on facts and judgments that are specific to each unit. While it is possible for a state or regional planning authority to model different retirement scenarios, these scenarios are based on assumptions that cannot account for the highly sensitive and confidential financial information that a unit owner is likely to rely on in making its decision.

Should the owner of a power plant decide to retire a unit because the unit cannot be economically retrofitted to meet the new EPA regulations, it must notify the state or regional planning authority of its decision. The regional planning authority must then determine the reliability implications of the retirement and consider next steps: (1) is there enough available generation and/or transmission to allow the unit to retire without adversely affecting reliability, or (2) will the retirement create the need for new generation, transmission, or other resources (such as demand-side resources) in order to maintain reliability?

Like a unit owner's decision to retrofit or retire, the reliability consequences of a retirement will be dependent on the specific facts of each case, each locality, and each region. While the EPA regulations are not expected to affect our resource adequacy as a nation, they may present reliability issues in particular localities or regions. In some regions, conditions may be such that a retirement, or even several retirements related to the new EPA regulations will not create a reliability concern. In other areas, the retirement of even a single unit may create the need for an alternative.

In this regard, I believe that for studies about the potential effects of the EPA regulations to have the most accuracy and predictive value, they must be conducted after the regulations are final and unit owners have decided whether to retrofit or retire. Studies under these conditions do not require the extensive number of assumptions required for a nation-wide analysis and are more likely to identify the regions that may face reliability concerns.

If a retirement does create a potential reliability issue, the unit owners, in conjunction with state and regional planning authorities, must determine what resources will replace the unit, how long it will take to bring the replacement resources into service, and what to do in the interim. Given the long lead times for certain types of resources, there may be a gap of time when a replacement facility is not available, but the retiring unit is no longer compliant with EPA regulations. In such cases, a time-limited waiver of EPA regulations may be needed. In some cases, a "reliability must-run" (RMR) contract may also be needed to allow the power plant to operate within certain discrete parameters for a limited period of time.

It is important to note that the process I just described is not unique to potential retirements related to the EPA's regulations. State and regional planners have used, and continue to use, this general process for any retirement, including those driven primarily by market conditions. The EPA regulations are significant in that they present the potential for significant retirements in the same timeframe. As I have said, however, whether and how this affects reliability is dependent on the highly specific facts present in each region and locality.

Once the local reliability considerations of a particular unit's retirement are known, there will need to be flexibility in specific cases. I believe that the EPA should and does understand this issue.

I do believe, however, that any waivers or flexible solutions must be targeted and discrete. Specific reliability analyses at the local and regional level are much more meaningful than nation-wide estimates. The circumstances of each retirement and need for replacement facilities are fact-specific. I do not personally support a blanket delay of EPA regulations, but will certainly champion specific extensions where needed for reliability.

Because of our jurisdiction over regional transmission planning, utility rates, and reliability standards, FERC should be actively involved in these issues when they arise. I believe that FERC can play an important role in discussions among regional planning authorities, regional reliability entities, the North American Electric Reliability Corporation, utilities, states, and the EPA. While FERC does not have authority to require utilities to build generation or transmission capacity for the adequacy of electric facilities or services, it can use the authority and expertise it does have to help ensure that planning processes allow utilities and planners to assess reliability issues as early as possible, so that adequate measures can be put into place to assure grid reliability.

For example, FERC can examine and approve market rules designed to facilitate reliability. In this regard, the Commission has previously approved locational pricing and forward capacity markets as mechanisms to send price signals about where and when new supply resources are needed. I believe that these market constructs, while not present in all parts of the country, properly price the marginal value of capacity and help to mitigate the concerns that would arise in their absence. I also believe that it would be helpful for FERC to sponsor a workshop (or series of workshops) that brings together states, utilities, regional authorities, and other stakeholders to discuss the impacts of the EPA regulations and assess what tools we collectively have at our disposal. As my remarks suggest, I believe we should focus on ensuring that planners have the tools to respond to local and regional reliability issues.

I believe that we as a nation can ensure that the EPA's proposed air and water regulations do not adversely affect reliability, provided we ensure that there is coordination and flexibility in their implementation.

Thank you very much.

Mr. WHITFIELD. Thank you, and thank all of you for your testimony.

Ms. LaFleur, you made the comment that you thought it would be useful to have a workshop and bring in interested parties to maybe better coordinate or look at this issue of reliability in a more comprehensive way. Is that correct?

Ms. LAFLEUR. Yes, and to look at the tools to make sure we have all the right tools in our tool chest.

Mr. WHITFIELD. Mr. Wellinghoff, do you have any plans to have a workshop like Ms. LaFleur is discussing?

Mr. WELLINGHOFF. I don't have any plans at this point in time. We have had a number of discussions with the planning authorities that come into FERC all the time and have discussions with them about the tools that they have available to adequately address the EPA proposed regulations. I actually talked to David Owens the other day from EEI about this issue of a workshop. He didn't feel that that was something that would be necessary from an industry perspective. So I haven't seen the need for it at this point in time.

Mr. WHITFIELD. Are there any other commissioners that believe that a workshop like Ms. LaFleur is talking about would be useful? Mr. Moeller?

Mr. MOELLER. Well, I have been in favor of it because I think we can get some of these issues out there, we can talk about some of the reliability implications that need to be drilled down. I can go into more detail if you would like.

Mr. WHITFIELD. Mr. Spitzer?

Mr. SPITZER. Mr. Chairman, I am certainly respectful of Commissioner LaFleur's effort to get more discussion. My view would be, I would rather have that take place before the rules become final so that we are not dealing with a done deal that is able to—makes it more difficult to deal with a final rule as opposed to during the planning process of the promulgation of the rule.

Mr. WHITFIELD. Mr. Norris?

Mr. NORRIS. Thank you. As I said, another meeting, another study with multiple scenarios on the table really doesn't, in my mind, get us anywhere. The analysis should be, do we have the tools available. I believe we have tools available now. Once we know what the rules are, we see what the impact is going to be and see what the impact is in fact in motion, then a workshop would be useful to say is that tool right or do we need to change that based on what we are seeing happening in the marketplace, what we are seeing happening with plant retirement decisions. But to have a meeting now would be, in my mind, like another one of the studies. We need to have—I think a workshop following the implementation of rules to make sure we are watching this, we are being vigilant about how reliability is being impacted may be a very productive outcome.

Mr. WHITFIELD. You say that you have the tools available and yet Mr. Wellinghoff in his testimony talked about that he felt like the best entities to really look at reliability because he said he did not have adequate resources was the utilities and other entities. But you say you have the tools necessary to look at reliability.

Mr. NORRIS. I believe that is right because I think we have tools, we oversee the marketplace in those independent system operations/regional transmission organizations, so if they identify a problem out there, they can come to us and we can look at market rules and make adjustments. The States have tools through their oversight of generation and their integrated resource planning processes to address situations. I didn't mean to imply that we have the only tools. We have tools. There are multiple tools throughout this situation at DOE, at the EPA with the possibility for consent decrees. Also, the time I have already given to comply with these rules.

Mr. WHITFIELD. Mr. Wellinghoff, does FERC intend to update its preliminary assessment in light of the new information and proposals issued by EPA?

Mr. WELLINGHOFF. No.

Mr. WHITFIELD. I noticed back in October, the FERC staff was recommending to conduct additional reliability studies.

Mr. WELLINGHOFF. I am sorry. What are referring to, Mr. Chairman?

Mr. WHITFIELD. In October, the Office of Electric Reliability at FERC said that the staff will continue to conduct reliability studies relating to this issue, but from your perspective, there is no need for additional assessment, I take it?

Mr. WELLINGHOFF. No specific assessment. Those studies would relate to the interface between EPA and the planning regions and those studies would in fact look at the assurances that there is proper information sharing between the planning authorities that have the tools. And when we talk about the tools that Commissioner Norris was talking about, we have tools as well. Our tools are regulatory tools. The planning authorities are planning modeling tools and actually do drill down and do the discrete analysis that is necessary to really determine what are the mitigation strategies and activities at the planning level to ensure reliability. Those are the tools they have. The tools we have are things like our Order 1000 which we recently issued. We explicitly set forth for the planning authorities the requirement that they look at public policy as part of their planning. That is the tool we have.

Mr. WHITFIELD. Let me just ask one other question. I know that in March you all came out with an order relating to demand response, which was supposed to address problems at peak periods, and can all of you say very comfortably that you are really not concerned about reliability, the impact on reliability that the environmental regulations that EPA would have?

Mr. WELLINGHOFF. That particular order on demand response actually was for using demand response in the energy markets as opposed to the capacity markets, which would have been the peak periods.

Mr. WHITFIELD. OK. Mr. Moeller?

Mr. MOELLER. I am not exactly sure of your question, Mr. Chairman.

Mr. WHITFIELD. Actually, I have gone a minute over anyway so we will get back to it.

Mr. Rush, you are recognized for 5 minutes.

Mr. RUSH. I want to thank you, Mr. Chairman.

Chairman Wellinghoff, recently Senator Murkowski issued a press release stating, and I quote, "The Commission staff has preliminarily estimated that up to 81 gigawatts of existing generation are 'likely' or 'very likely' to be retired as a consequence of new EPA rules." Based on subsequent statements, however, you clarified that this estimate was way high because it included significant assumptions about the rules that were ultimately found to be incorrect. Would you please comment on——

Mr. WELLINGHOFF. Well, as Mr. Waxman indicated in his opening statement, that back-of-the-envelope analysis was just a preliminary one to set the stage for us to enter into some discussions with EPA to determine the appropriateness of EPA's interaction with the planning authorities to determine ultimately how these rules could impact their planning requirements in each individual region. There was no intent for the use of that particular number to be used in any way for planning. It is not a planning number. It should not be used for planning. It is not appropriate to do that. And I believe in fact that number as the EPA's number of 10 is irrelevant because what is relevant are the numbers that will be developed by the planning authorities in each region determined discretely what the impacts are and how those impacts can best be mitigated in the time frames necessary.

And I want to add to that that I think Commissioner LaFleur has mentioned, and I know that Commissioner Spitzer in his extended testimony has mentioned, you know, this flexibility that we need to put into the process. For example, the ISOs and RTOs have recommended a discrete safety valve that could be put in for particular locational plants that may have problems that are revealed in this planning process. We need some level of flexibility for those. But we do not need to, you know, stop these rules going forward. I think these rules are appropriate. These rules in fact do what needs to be done in this country, and that is, internalize the external costs that we have with respect to electricity, and once we start internalizing those costs, we will start giving the right market signals to consumers and the people who are consuming the energy, and those market signals can make us all more efficient and more prosperous and more economic.

Mr. RUSH. Well, Chairman Wellinghoff, I hear you saying that State or regional planning processes to identify future required infrastructure and resources are the appropriate vehicle for addressing EPA rules reliability impact. Give us a little bit more of the, say, intimate details. How will this process really work?

Mr. WELLINGHOFF. Well, I think you will actually get some of the details from your next panel because there will be representatives from PJM. That is one of the planning authorities. There will also be representative from ERCOT, which is another planning authority, and they will describe for you how they go through their planning process, and in fact, they have a planning process that is either every year or every other year that looks forward on a 5-, 10- or 20-year basis, depending upon the—actually, it is a 10-, 15- or 20-year basis, depending upon the planning authority itself, and so they are very well equipped with discrete models that are specific to their region, that take data from all the resources in the region including the power plants, transmission lines and the demand-side resources and determine through that analysis on an ongoing rolling basis what is needed with respect to ensuring reliability in their particular regions. Now, we oversee that but it is not our job to do——

Mr. RUSH. My time——

Mr. WELLINGHOFF [continuing]. Central planning. We don't think we should be in the business of central planning.

Mr. RUSH. Sorry for interrupting, but my time has come to a close. I have a question for all the commissioners. Are all of you aware or familiar with the recent bipartisan CRS report concluding that the primary impact of EPA's rules will primarily impact smaller, older, inefficient coal plants, many of which are uneconomic regardless of EPA's rules? Can you comment on the report's conclusion that the Nation has enough excess generation capacity that retirement of 45 gigawatts of capacity by 2014 will have little effect on reserve margins?

Mr. WELLINGHOFF. I know, for example, Mr. Rush, in my State, Nevada, the Nevada utility has a 60 percent excess capacity above its reserve margin so they have huge amounts of excess capacity in my particular State, and as Congressman Waxman indicated, there is at least 100 gigawatts of excess capacity above the existing capacity. Plus if we look at the amount of new resources that we need to put in, even if it is 80 megawatts, say, I think Commissioner Norris indicated in his testimony, in his full testimony, between 2002 and 2003 we put in over 200 gigawatts of new capacity in this country. So it is not unprecedented. It is something that has happened before and something that we certainly can take care of with respect to proper planning, proper analysis and review by the planning authorities.

Mr. RUSH. Anybody else?

Mr. MOELLER. Congressman Rush, I am familiar with both studies and their conclusions, but here is my concern from a reliability perspective. Smaller plants are typically dirtier and older but there are advantages in the system to smaller plants. They ramp up and down faster. They might be in locations where the voltage support is key, and I can go through a variety of other examples where where they are located can make a lot of difference, and that is why I think we need to dig down deeper into the impacts here because there will be a disproportionate number of smaller, older, dirtier plants affected but their role in the overall electric grid needs to be better analyzed.

Mr. SPITZER. Congressman, the aggregate studies aren't helpful on the question of reliability. They have some merit in determining potentially wholesale power prices across the country and across the grid. But as my colleagues have all pointed out, location matters in electricity, and a substantial excess capacity in Nevada may not help the folks in Arizona, where I come from, if three coal plants that have issues disappear from the grid. So it is the local impacts that are serious, and that is why we are so interested in working with the local planning authorities because FERC doesn't have the authority with regard to demanding retirement or construction of plants, and it was expressively reserved away from us in EPACT 2005 Section 215. So we are more concerned with the local impact on reliability as opposed to some of these aggregate macro studies.

Mr. WHITFIELD. Mr. Rush, your time is expired.

At this time I will recognize the gentleman from Illinois, Mr. Shimkus.

Mr. SHIMKUS. Thank you, Mr. Chairman. I am going to be quick. I have got tons I want to cover.

First of all, I want to submit for the record the Wall Street Journal editorial that basically says calling for an EPA moratorium. The second line says "immediately suspend the Environmental Protection Agency's bid to reorganize the U.S. electricity industry."

[The information follows:]

[redacted]

THE WALL STREET JOURNAL.
WSJ.com

REVIEW & OUTLOOK | AUGUST 29, 2011

An EPA Moratorium

Obama has the power to delay new rules that will shut down 8% of all U.S. power generation.

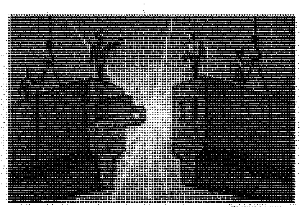
Since everyone has a suggestion or three about what President Obama can do to get the economy cooking again, here's one of ours: Immediately suspend the Environmental Protection Agency's bid to reorganize the U.S. electricity industry, and impose a moratorium on EPA rules at least until hiring and investment rebound for an extended period.

The EPA is currently pushing an unprecedented rewrite of air-pollution rules in an attempt to shut down a large portion of the coal-fired power fleet. Though these regulations are among the most expensive in the agency's history, none were demanded by the late Pelosi Congress. They're all the result of purely bureaucratic discretion under the Clean Air Act, last revised in 1990.

As it happens, those 1990 amendments contain an overlooked proviso that would let Mr. Obama overrule EPA Administrator Lisa Jackson's agenda. With an executive order, he could exempt all power plants "from compliance with any standard or limitation" for two years, or even longer using rolling two-year periods. All he has to declare is "that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so."

Both criteria are easily met. Most important, the EPA's regulatory cascade is a clear and present danger to the reliability and stability of the U.S. power system and grid. The spree affects plants that provide 40% of U.S. baseload capacity in the U.S., and almost half of U.S. net generation. The Federal Energy Regulatory Commission, or FERC, which is charged with ensuring the integrity of the power supply, reported this month in a letter to the Senate that 81 gigawatts of generating capacity is "very likely" or "likely" to be subtracted by 2018 amid coal plant retirements and downgrades.

That's about 8% of all U.S. generating capacity. Merely losing 56 gigawatts—a midrange scenario in line with FERC and industry estimates—is the equivalent of wiping out all power generation for Florida and Mississippi.


Getty Images

In practice, this will mean blackouts and rolling brownouts, as well as spiking rates for consumers. If a foreign power or terrorists wiped out 8% of U.S. capacity, such as through a cyber attack, it would rightly be considered an act of war. The EPA is in effect undermining the national security concept of "critical infrastructure"—assets essential to the functioning of society and the economy that Mr. Obama has an obligation to protect.

He would also be well within the law to declare that the EPA's rules are technologically infeasible. Later this year, for example, the EPA will release regulations requiring utilities to further limit mercury and other hazardous pollutants. Full compliance will be required by 2015, merely 36 months after the final rule is public, and plants that can't be upgraded in time will be required to shut down.

Yet this is nearly impossible to achieve. Duke Energy commented to the EPA that its average lead time for retrofitting scrubbers was 52 months, including the design, purchase and installation of equipment and the vagaries of the environmental permitting process. For Southern Co., another big utility, it was 54 months, over 16 scrubber systems. Filter systems usually take anywhere from 34 to 48 months end to end.

The environmental regulatory system is so rigid that once a rule is in motion it is almost impossible to stop or roll back in a way that can withstand scrutiny in the courts. Mr. Obama allowed Ms. Jackson to begin the process, but we rehearse these details to show that he has the legal authority to minimize her damage. An executive order would not make these rules more rational or change them in any way. All it would do is delay them, giving businesses more time to prepare and to amortize the costs over a longer time.

The larger issue is whether the Administration's green campaign is more important than economic growth. The EPA's own lowball cost estimate for the mercury rule is $11 billion annually, though the capital expenditures to meet the increasingly strict burden will be far higher. That investment could be put to more productive uses than mothballing coal assets and replacing them with more expensive sources like natural gas. With nearly a tenth of America out of work, $11 billion year after year adds up.

We don't expect Mr. Obama to take our advice and tell his regulators to cool it, but no one should believe the excuse that his hands are tied. Whatever he decides will speak volumes about his real economic priorities.

Actually, I would argue that some of you would like to do the same thing and impose a moratorium on EPA rules, at least until hiring and investment rebound for the extended period.

We are in an economic crisis. We need jobs. Put the first slide up, please. For 1,000 gigawatts, these are the jobs in these industrial sectors. Five hundred jobs in the nuclear power industry, 220 jobs in the coal industry, 90 in the wind, 60 in natural gas when we shutter these plants based upon these EPA rules, and I am going to argue, your negligence, we lose those jobs. And when these locations are in poor, rural southern Illinois, they are the primary tax base for local government. So you have a lot on your plate, and I think you all are being pretty negligent.

You are the reliability folks based upon Section 215 of the power act, your own mission statement, your Office of Energy Reliability, recent actions that you have taken—put up the next slide. This isn't the fight against EPA's projections and your projections. These are the other industrial sectors that says these are the powers that are going to be offline if we allow these rules to go, and on average, you are at 60 gigawatts of power, 60. EPA is at 10. They are doing the analysis of what the reliability and the production of the bulk generating plants. Just give me a break.

Chairman, do you still believe as you were quoted, and I would like to submit this for the record, that we may never need any more coal or nuclear power in this country, that we can do this all on green and that will be our baseload production for the future?

[The information follows:]

The New York Times

[redacted]

April 22, 2009

Energy Regulatory Chief Says New Coal, Nuclear Plants May Be Unnecessary

By NOELLE STRAUB AND PETER BEHR, Greenwire

No new nuclear or coal plants may ever be needed in the United States, the chairman of the Federal Energy Regulatory Commission said today.

"We may not need any, ever," Jon Wellinghoff told reporters at a U.S. Energy Association forum.

The FERC chairman's comments go beyond those of other Obama administration officials, who have strongly endorsed greater efficiency and renewables deployment but also say nuclear and fossil energies will continue playing a major role.

Wellinghoff's view also goes beyond the consensus outlook in the electric power industry about future sources of electricity. The industry has assumed that more baseload generation would provide part of an increasing demand for power, along with a rapid deployment of renewable generation, smart grid technologies and demand reduction strategies.

Jay Apt, a professor at Carnegie Mellon University's Electricity Industry Center, expressed skepticism about the feasibility of relying so heavily on renewable energy. "I don't think we're where Chairman Wellinghoff would like us to be," Apt said. "You need firm power to fill in when the wind doesn't blow. There is just no getting around that."

Some combination of more gas- or coal-fired generation, or nuclear power, will be needed, he said. "Demand response can provide a significant buffering of the power fluctuations coming from wind. Interacting widely scattered wind farms cannot provide smooth power."

Wellinghoff said renewables like wind, solar and biomass will provide enough energy to meet baseload capacity and future energy demands. Nuclear and coal plants are too expensive, he added.

"I think baseload capacity is going to become an anachronism," he said. "Baseload capacity really used to only mean in an economic dispatch, which you dispatch first, what would be the cheapest thing to do. Well, ultimately wind's going to be the cheapest thing to do, so you'll dispatch that first."

He added, "People talk about, 'Oh, we need baseload.' It's like people saying we need more computing power, we need mainframes. We don't need mainframes, we have distributed computing."

The technology for renewable energies has come far enough to allow his vision to move forward, he said. For instance, there are systems now available for concentrated solar plants that can provide 15 hours of storage.

"What you have to do, is you have to be able to shape it," he added. "And if you can shape wind and you can effectively get capacity available for you for all your loads.

"So if you can shape your renewables, you don't need fossil fuel or nuclear plants to run all the time. And, in fact, most plants running all the time in your system are an impediment because they're very inflexible. You can't ramp up and ramp down a nuclear plant. And if you have instead the ability to ramp up and ramp down loads in ways that can shape the entire system, then the old concept of baseload becomes an anachronism."

'A lot that is still not understood'

Asked whether his ideas need detailed studies, given the complexity of the grid, Wellinghoff said the technology is already moving that way.

"I think it's being settled by the digital grid moving forward," he said. "We are going to have to go to a smart grid to get to this point I'm talking about. But if we don't go to that digital grid, we're not going to be able to move these renewables, anyway. So it's all going to be an integral part of operating that grid efficiently."

The North American Electric Reliability Corp. reported last week on challenges in integrating a twentyfold expansion of renewable power into the nation's electricity networks but did not specifically address whether additional baseload generation would be needed. A spokesperson for NERC did not have an immediate response to Wellinghoff's comments today.

Revis James, who directs energy technology assessment for the Electric Power Research Institute, said recently that it is not clear how fast renewable energy can be added without creating reliability issues. "No one knows what the magic number is," he said. "Are we moving too fast? On the policymakers' side, there's a lot that is not still understood about the implications of a large share of renewables."

Impact on nuclear power

Wellinghoff's statement -- if it reflects Obama administration policy -- would be a huge blow to the U.S. nuclear power industry, which has been hoping for a nuclear "renaissance" based on the capacity of nuclear reactors to generate power without greenhouse gas emissions.

Congress created significant financial incentives to encourage the construction of perhaps a half-dozen nuclear plants with innovative designs, and Energy Secretary Steven Chu has promised Congress to accelerate awards of federal loan guarantees for some of these proposals.

But a major expansion in U.S. nuclear energy would require a high effective tax on carbon emissions from coal plants, or an extended loan guarantee and tax incentive policy, according to the Congressional Research Service and outside consultants. The leading energy bills before Congress do not provide more loan guarantees.

"If expansion of nuclear plants is the nation's policy, then Congress has to recognize that the U.S. energy companies cannot afford to do this alone," said Paul Genoa, policy director for the Nuclear Energy Institute, in a recent interview.

"The president needs to show his cards on nuclear energy," said energy consultant Joseph Stanislaw, a Duke University professor. "He cannot keep this industry, which must make investments with a 50-year or longer horizon, in limbo for much longer."

"I think [new nuclear expansion] is kind of a theoretical question, because I don't see anybody building these things, I don't see anybody having one under construction," Wellinghoff said.

Building nuclear plants is cost-prohibitive, he said, adding that the last price he saw was more than $7,000 a kilowatt -- more expensive than solar energy. "Until costs get to some reasonable cost, I don't think anybody's going to [talk] that seriously," he said. "Coal plants are sort of in the same boat, they're not quite as expensive."

Can renewables meet demand?

There's enough renewable energy to meet energy demand, Wellinghoff said. "There's 500 to 700 gigawatts of developable wind throughout the Midwest, all the way to Texas. There's probably another 200 to 300 gigawatts in Montana and Wyoming that can go West."

He also cited tremendous solar power in the Southwest and hydrokinetic and biomass energy, and said the United States can reduce energy usage by 50 percent. "You combine all those things together ... I think we have great resources in this country, and we just need to start using them," he said.

Problems with unsteady power generation from wind will be overcome, he said.

"That's exactly what all the load response will do, the load response will provide that leveling ability, number one," he said. "Number two, if you have wide interconnections across the entire interconnect, you're going to have a lot of diversity with that wind. Not all the wind is going to stop at once. You'll have some of it stop, some of it start, and all of that diversity is going to help you, as well."

Push for grid modifications

But planning for modifying the grid to integrate renewables must take place in the next three to five years, he said.

"If we don't do that, then we miss the boat,"Wellinghoff said. "That planning has to take place so you don't strand a lot of assets, a lot of supply assets."

Unlike coal and nuclear, natural gas will continue to play a role in generating electricity, he said.

"Natural gas is going to be there for a while, because it's going to be there to get us through this transition that's going to take 30 or more years."

Chu reiterated before the House Energy and Commerce Committee today that he supports loan guarantees for new nuclear power plants and is working with the White House on the issue.

"I believe nuclear power has to be part of the energy mix in this century," Chu said.

Chu also noted today that nuclear technology, along with renewables, is an area where the United States has lost its lead. "We are trying to start the American nuclear industry again," he said.

Coal currently provides half of U.S. power, while nuclear energy accounts for about 20 percent.

Senior reporter Ben Geman contributed.

For more news on energy and the environment, visit www.greenwire.com.

Mr. WELLINGHOFF. That particular statement in context was this: I believe that going forward, the resources that we have in this country include wind, solar, geothermal, natural gas——

Mr. SHIMKUS. And your statement——

Mr. WELLINGHOFF. Excuse me.

Mr. SHIMKUS. Reclaiming my time, Chairman.

Mr. WELLINGHOFF. I wasn't done. That was only half my answer.

Mr. SHIMKUS. I know your statement.

Mr. WELLINGHOFF. If that is all you want, that is fine.

Mr. SHIMKUS. I understand who your loyalties lie to, and it is to the environmental left and it is to Harry Reid and this green agenda that can't produce the power needed for reliability and destroys all those jobs I just put up on the slide. Now, you were quoted as saying no more coal, no more nuclear. That is fine but you also have your own—your own staff said you can't have a one-to-one replacement. So that was the question of the chairman: Can you have a one—your own staff says you can't have a one-to-one replacement on power generation solely on green power.

Now, let me go to the EPA.

Mr. RUSH. Mr. Chairman.

Mr. SHIMKUS. Where I am really concerned on the negligence here is the EPA in their rule says in addition EPA itself has already begun reaching out to key stakeholders. You all are included in that. This is their rule. You are included. But you are saying, no, we are not going to determine this until after EPA promulgates these rules. Now, EPA is asking you to be involved. Actually, the rule says you, NERC, FERC, the public utility commissions, but your own testimony here, and especially Mr. Wellinghoff's, Mr. Norris's, Ms. LaFleur's says we are going to do it afterwards. Where does that leave us with after the fact on this debate on reliability? Do you reject that this is in the EPA in their rule?

Mr. WELLINGHOFF. Mr. Congressman, with all due respect, my testimony is not that we are going to do it afterwards. My testimony is that——

Mr. SHIMKUS. Your statement is that you are going to do it afterwards.

Mr. WELLINGHOFF. No, it is not. My statement is that the planning authorities are doing it now. In fact, PJM was in my office the other day——

Mr. SHIMKUS. I am not talking about planning. I am talking about you.

Mr. RUSH. Point of order, Mr. Chairman.

Mr. SHIMKUS. What is the matter, Mr. Rush? Am I getting too close to home?

Mr. RUSH. No, point of order. You aren't allowing the witness to answer——

Mr. SHIMKUS. I have got the questions.

Mr. RUSH. You are badgering the witness.

Mr. SHIMKUS. I hope I get my time recovered, Mr. Chairman.

Mr. WHITFIELD. You will.

Mr. RUSH. This is not within the established decorum of this subcommittee.

Mr. WHITFIELD. Now listen, Mr. Rush. He has the opportunity to ask questions. He is asking questions.

Mr. RUSH. But he——

Mr. WHITFIELD. Let me just say something else. You used the word "jihadist" in your opening statement.

Mr. RUSH. I only borrowed that term——

Mr. WHITFIELD. And I tell you what, I think that is——

Mr. RUSH. I only borrowed that term from your side, Mr. Chairman. I only borrowed that term from my friend from southern Illinois who used it yesterday, and you——

Mr. WHITFIELD. Who was that?

Mr. RUSH. He knows exactly who it is, my friend from southern Illinois.

Mr. SHIMKUS. I would check the transcript, Mr. Rush.

Mr. RUSH. I heard you say it.

Mr. WHITFIELD. Let me just say, these issues are quite contentious. We have very strong feelings about them. But we don't need to use——

Mr. RUSH. Just be courteous to the witness. That is I all I am saying.

Mr. WHITFIELD. Let us not use these words "jihadist" any more on either side. Now, Mr. Shimkus has 30 seconds left so let him——

Mr. SHIMKUS. I am glad we have kept the slide up here. For my friend from Chicago, those job statistics are per generation per 1,000 megawatts are those are the jobs that are going to be lost, and look at where coal and look at where natural gas is and look where wind is. And I would just ask this question. It is clear in your testimony provided here today in the materials provided by FERC detailing the meetings between EPA, FERC, DOE that the level of coordination suggested by EPA has not occurred. That is based upon your testimony and your documents. Why has this not happened? And Mr. Chairman, if I could ask each member of the Commission to answer that, I would appreciate it.

Mr. WHITFIELD. Yes, go ahead and answer, please.

Mr. WELLINGHOFF. Thank you. I believe the level of coordination that has occurred between our agency and EPA has been sufficient. I believe that we are continuing to coordinate with EPA and will do so to ensure that EPA can work with the planning authorities, provide them with the data that is necessary to have those planning authorities to take into account the EPA regulations and incorporate that into their final determinations to mitigate any impacts with respect to reliability.

Mr. MOELLER. Congressman, I believe there has been some informal discussions between the staffs and there have been a few meetings, one of which I was involved in between commissioners and EPA officials, but I have called for a more open process or transparent process so that we can get these issues in a higher spotlight.

Mr. SPITZER. Mr. Chairman, Congressman Shimkus, I wasn't invited to the EPA meetings but I am of the strong believe that all five FERC commissioners are committed to reliability as is the case often——

Mr. SHIMKUS. You weren't invited?

Mr. SPITZER. Well, there were quorum issues and other reasons for that, and I was——

Mr. SHIMKUS. So they only invited Democrat commissioners?

Mr. SPITZER. I believe Commissioner Moeller was invited, and the chairman did advise me and notified me of these and has advised me of the progress of these, and all five FERC commissioners are committed to reliability. I would suggest to you five points. I will try to be quick running through them. Granularity—it is at the local level that these decisions are made. Power plant operators, State regulators who will follow us and FERC share responsibility for providing reliable power at reasonable prices to the ratepayers of the United States and it is that granularity that is essential, and FERC doesn't have the authority to mandate that a utility build a power plant nor does have FERC have the authority to require a utility to retrofit or retire a plant, and that was specifically decided by the Congress in 2005, and my friends who are going to testify next would be very angry in fact if FERC were to trespass on that authority.

There are many variables. There are three plants in Arizona that are threatened with regional haze, which is not part of this suite of EPA regulations. It goes to a visibility issue over the Grand Canyon. And there are also economic issues apart from EPA. There are timing issues, and I try to discuss in my testimony the need for a safety valve to give more time. And then the fact that there are iterative processes. A one-time freeze frame doesn't do the job and the planning agencies look in some cases every year in some cases every 6 months. And then finally, I like all fuels, Mr. Chairman, members. I think there is room for all fuels. I would like to see fair and equitable rules so that market forces determine ultimately what power plants get constructed.

Mr. WHITFIELD. We have gone 3 minutes over, so I am going to stop this and recognize Ms. Castor for 5 minutes of questions.

Ms. CASTOR. Thank you, Mr. Chairman and Ranking Member Rush, and thank you to the witnesses for your testimony today.

Opponents of EPA's public health rules raise questions over the potential for the retirements of the old, inefficient coal plants which I believe raises further questions about the electric industry's ability to address those retirements should they occur. First, several independent studies point to the current availability of excess generation capacity, what the chairman and Mr. Rush have discussed previously. The Congressional Research Service explained that there is a substantial amount of excess capacity, mostly from natural gas plants built during the last decade, and the Analysis Group also calculated that the electric sector is expected to have over 100 gigawatts of surplus generating capacity in 2013.

Chairman Wellinghoff, you discussed this a little bit. Do you agree with these independent analyses that everyone should consider plant retirements and the existing excess capacity as we move forward?

Mr. WELLINGHOFF. Well, certainly I agree that the planning authorities in considering the resource need for the future in those planning exercises need to look at not only potential retirements from the EPA regulations but also the amount of existing capacity that may be in excess in those particular regions as well as other resources that we are now depending upon including demand response, energy efficiency, distributed generation are all resources that are available within those planning regions, and in fact, resources that we require in our rules now, in our Order 890 and in our Order 1000 that the planning authorities consider in doing their overall assessments.

Ms. CASTOR. I think you are right, because the focus in this resilient energy, the electric energy sector is not simply on what is happening with the retirement of old, inefficient coal plants. It is so much larger than that. In addition to building, monitoring the excess existing capacity, we can also—I think the sector can build additional capacity. The independent analysts also point to the electric industry's proven track record of quickly building new capacity when it is needed. For example, the Congressional Research Service noted that between 2000 and 2003, electric companies added over 200 gigawatts of new capacity, and that is far more than anyone has suggested will be needed to offset any retirements resulting from EPA's rules, and as you mentioned, other options are demand response, energy efficiency measures that could lower the amount of generating capacity that the grid would need.

Commissioner Wellinghoff, do you think that this resilient electric energy sector has the ability to respond to potential retirements by building new capacity? You mentioned reducing demand through energy efficiency and demand response but what do you think?

Mr. WELLINGHOFF. It has the ability to respond in many ways, and that is ultimately why it is so important for us to get the market signals right, and that is why EPA is doing the right thing by getting the market signals right, by internalizing what are now external costs. If we can internalize those costs in the price, in the ultimate price, then we can find the lower-cost alternatives to compete and come into the market and make appropriate substitutes economically.

Ms. CASTOR. Commissioner Norris, you indicated in you testimony that you have reviewed an array of studies and reports that analyze the potential impacts of EPA rules and steps that can be taken to cope with any retirements. What do you think? Do you believe that we have many options available—excess capacity, energy efficiency, demand response—for the industry to respond to any retirements and maintain reliability?

Mr. NORRIS. Yes, that is what I maintained in my testimony. I can't remember, I think it was Commissioner Spitzer that made the point, I think most of the studies indicate we will not have a resource adequacy problem across the country. There could be localized concerns, and that is why I maintain that we have tools to address those local concerns. But we have, and as you noted, the 2002–2003 data, the adding of 2,000 gigawatts of new capacity in this country was done in 3 years. That is double, more than double what the projected retirements might be.

I think it is also important to note—in fact, I will give you this example. When I was chairman of the Iowa Public Service Commission, I believe it was 2007, it might have been 2008, I voted to approve a generation certificate for a new coal plant but I rejected in the rationale for that argument that we should build this plant because it produced X amount of new jobs. Here is why I rejected it. If we take away jobs in old and inefficient plants, those jobs don't go away; they shift to more efficient production. That is not a bad thing for our economy. I am sensitive to the local concerns but the energy is still needed. It has just moved the jobs to generate that energy are done in a more efficient way and a more productive way for our economy.

Ms. CASTOR. Thank you very much.

Mr. WHITFIELD. I am going to just make one comment, Mr. Norris. This argument about, we have got new jobs over here, but for the people who lose their jobs, they are gone and it has the impact on them and their families. So somebody may be able to pick up a new job in one part of the country but these people lose their jobs.

Mr. NORRIS. I am entirely sensitive to that, but most of these will be local reliability concerns, so it is my hope we can build new gas plants or build transmission at other facilities that help address the reliability concerns that may result from that. I am totally sensitive to people losing their jobs. Our economy changes a lot, that we shouldn't hold back efficiency.

Mr. WHITFIELD. Ms. McMorris Rodgers, you are recognized for 5 minutes.

Mrs. MCMORRIS RODGERS. Thank you, Mr. Chairman, and thank you, everyone, for your testimony and for being here today.

I come from eastern Washington, the Pacific Northwest, where the majority of our baseload is reliable, renewable hydropower, and I recognize that a lot of the rest of the country does not have the hydropower facilities and relies heavily on traditional fuels such as coal for their baseload. I am concerned about the EPA regulations and the potential to eliminate 131 gigawatts of baseload power with the assumption that there will be a one-for-one replacement with renewable sources, and what we are trying to work on is amending the implementation timeframe for many of these EPA job-crushing regulations and give energy producers the ability to meet the achievable standards in a reasonable timeframe.

What I would like to ask, where I would like to start is with Commissioner Moeller and Commissioner Spitzer. I think back to when I was first elected to Congress in 2004, and the cost of natural gas at that time, there was a concern that it was going to be going up in cost, and I would like to just ask, are there reliability concerns associated with becoming over-dependent on natural gas to generate electricity and what are the advantages to having a diversified source of energy?

Mr. MOELLER. Thank you, Congresswoman. As Commissioner Spitzer said and as I said in my written testimony, I am fuel-neutral. I think we need all fuels. I am a particular believer in hydropower, as you know. And we have to be concerned about becoming dependent on any source of fuel. The key is that 3 years ago we wouldn't have been having this kind of discussion because natural gas prices were three times what they are now. They are down for two reasons. To some extent, economic output it down, but we have also had come on the system this incredible resource of domestic shale gas, and that has had worldwide implications, and if you look at the futures markets, which could be wrong, we are looking at a decade or so of moderate natural gas prices. Of course, that can change. But for this gas to take the place of coal in baseload generation, you are making the assumption that it will stay at a moderate price and we will also have to expand the pipeline network in this country. That is not done overnight. It can be done. I think our staff in the Office of Energy Projects does an excellent job of certificating projects in a safe manner but it takes time, and I think you will have utilities and other entities testify to that effect.

Mr. SPITZER. Mr. Chairman, Congresswoman, natural gas is a wonderful success story for the ratepayers in the United States and it happened when the market signals sent price signals and new technology emerged, the horizontal drilling and the fracturing. That was a wonderful technological innovation. But we needed transmission to get the natural gas to the load centers, and FERC during my tenure has sited more miles of interstate natural gas pipelines than any time in the history of this country as well as natural gas storage facilities. So it was a combination of government working to put in infrastructure, steel in the ground, market signals and technology that created a great resource. I share your concern about overreliance on one particular fuel. I think we need all fuels, and obviously there is concern among those in the gas-producing sector that there may be potential political or regulatory backlash towards their fuel but there is room for all fuels.

A final point. The reason I am so concerned about the issue of forcing a generator to serve two masters, FERC's authority under Section 215 of the Federal Power Act to impose reliability penalties and potential EPA penalties. I share a trait in common with a former Member from your district who represented your district. For 25 years I was a tax lawyer representing taxpayer against the IRS, and there are some entities that are quite capable of conducting litigation against the federal government but for other entities it is a very daunting task, and it fills many with trepidation. And so I think for the reasons I stated in my testimony, it behooves both regulators to do everything they can to avoid creating this Hobson's choice where you will find yourself in violation of one rule or another. I am confident that we can do that.

Mrs. MCMORRIS RODGERS. Thank you. I have another question. Would the two of you describe some of the sunk transmission costs consumers are left paying when a power plant retires prematurely?

Mr. MOELLER. Some transmission costs would probably be determined on a very locationally specific matter but I think another concern would be that if again you have a smaller plant, say, between two larger towns that is needed for voltage support of the system, it doesn't put out a lot of energy but it puts the right amount of voltage support in, that would have to be replaced perhaps by more expensive and expansive transmission build-outs or another power plant in another place. That I think may even be a more significant cost than the sunk transmission costs.

Mr. SPITZER. Mr. Chairman, Congresswoman, Congress has recognized the need for transmission and authorized FERC to pursue transmission aggressively in many forms, and that is certainly—steel in the ground is important but the hypothetical you allude to about potential sunk costs, I think highlights the need for granular and iterative analysis by the State commissioners, who you will hear from, from the planning authorities and from the generators who through various opportunities to retrofit or repower power plants can make economic decisions based upon market forces.

Mr. WHITFIELD. At this time I will recognize the gentleman from Washington, Mr. Inslee, for 5 minutes.

Mr. INSLEE. Thank you. I am concerned about this GOP effort, not just for issues of public health but because I think it will adversely impact job creation in the United States, and this is a job-killing effort by the GOP and an effort to hang on to some old, inefficient economic activity rather than to create thousands of new jobs that would be associated with making our economy more efficient and more healthy, and I think the evidence is quite powerful in that regard.

I would point to a study that our next witness, Dr. Susan Tierney, will talk about suggesting that between 2010 and 2015, capital investments in pollution controls and new generation will create an estimated 1.46 million jobs, or about 291,577 year-round jobs on average for each of these 5 years. Transforming to a cleaner, modern fleet through retirement of older, less-efficient plants, installation of pollution controls and construction of new capacity will result in a net gain of over 4,254 operation and maintenance jobs across the eastern interconnection. The largest estimated job gains are in Illinois, 122,695; Virginia, 123,014; Tennessee, 113,138; North Carolina, 76,976; and Ohio, 76,240. Every single one of those jobs is at risk because of this wrongheaded, archaic, backward thinking of the GOP to think that we live in a static economy that doesn't create jobs when we go through transition, and this transition to a healthier United States is not just based on breathing or cardiovascular activity. It is based on job creation for thousands of new jobs. And this is an attack on jobs in my district, in my State. I will just mention some of them.

In Moses Lake, Washington, we make the substrate for solar cells, the largest manufacturer in the western hemisphere in Moses Lake, Washington. This bill is an attack on those jobs. In Seattle, Washington, we are making efficiency improvements. In Spokane, we have a company called Itron that is making products for the smart grid that is more efficient so we don't waste as much electricity. This bill is an attack on those jobs because it allows the continued pollution that damages our health and retards the creation of thousands of new jobs in these new industrial sectors.

So this bill is a job-killing job on a net basis. Yes, there is dislocation associated with any transition but we have got to understand that we have as many jobs to gain as we have to lose if we play our cards right, and some of these rules, as contentious as they are, recognize the value of new technologies. So I want to note, there seems to be some discussion that the only jobs that count are one coal plant in a Midwestern State. There are jobs all over the country that are at stake in this regard that will be lost if this bill becomes law and we stop the creation of all of these jobs.

And by the way, it is not just in the high-tech field. In my State, we have steel workers, iron workers, carpenters, laborers and longshoremen in the production of these new jobs. Just look at one wind turbine that goes up, and we have had a huge expansion of wind power in the State of Washington. One wind turbine, we ship stuff in, a longshoreman has got a job. Driving it up to eastern

Washington, a Teamster has a job. Putting it up, a laborer, a carpenter and an iron worker have a job. Stringing the wire to the wind turbine, an IBEW member has a job. Those jobs are at risk when we say that we are going to leave these old, dirty, polluting, unhealthy things at risk, and that is what is at risk and that is why I am opposed to this effort, besides the fact that we have got folks that want to be able to breathe.

Now, that is much more of a statement than a question, but if any of our panel would like to comment or criticize that statement, I would be happy to allow them to do so. There are no takers, and thank you for your agreeing totally with my position.

Mr. WHITFIELD. Thank you for that wonderful statement.

Mr. McKinley, you are recognized for 5 minutes.

Mr. MCKINLEY. The Congressman sure left the door wide open. There are just so many things to go on in these 5 minutes. Let me just address that one issue that was just brought up. Gina McCarthy was here just last week on this panel, and that question was raised to her, that very study I think that he is referring to that talked about 1–1/2 new jobs for every $1 million in environmental pollution controls put in effect, and she was asked about that, and she repudiated the study, said that was done independently and it doesn't wash. We used the example of a sawmill plant that was under the boiler MACT that it is going to cost them $6 million, and we asked her if she was going to create nine jobs, and she just laughed. She said that is the silliness of some of this, some of these reports that come out. They don't create new jobs; they destroy jobs.

And as far as the IBEW, it is my understanding, I have got correspondence from them that they oppose a lot of these, even though it does create short-term construction jobs. They understand the long-term impact of higher utility bills, what it is going to do to the American economy if we do place all these and raise our utility bills. It is one of the things we have very effectively—we have powerhouses throughout West Virginia, very effective with AEP, First Energy. These are some of the leaders in the Nation in what they have done in producing very effective power.

But my question back to the chairman, Mr. Wellinghoff, has to do with—it is my understanding—I am just 8 months into this job, and I saw the—it absolutely is accurate that there is a mindset here in Congress that I have come to understand attacking coal. Coal is the backbone of West Virginia, and it is crucial, but it wasn't until I came to Congress, Mr. Chairman, that I realized how much there was this attack on coal, and what I saw was the power plants were not shutting down. These powerhouses were not shutting down until the EPA started raising the regulations. They were meeting the standards currently but then when they raised the standards, these powerhouses said maybe they are going to shut down. There have been announcements of three to five plants in West Virginia that are going to shut down because of these regulations, but they were meeting the current standards until the new standard came into effect, and a new standard at a time when we have no jobs created whatsoever last month, 14 million people out of work. I think that is all that we are asking for, is this the time to be implementing new standards.

So my question to you is, if it comes down to health issues, saving a person's health of saving a person's job, what would you recommend specifically?

Mr. WELLINGHOFF. Thank you for that question, Congressman McKinley. It is my purview to recommend either. My purview is to recommend that we have a more efficient electric system and that markets in this country, I think we can rely on markets in this country to determine how that electric system should operate, and so what I advocate is that we do everything we can to make sure that those markets are structured properly and they are not jerry-rigged. If we can structure the market properly, that means we need to incorporate all the costs of a particular product in that market.

Mr. MCKINLEY. That is just about as evasive as all the other panels have been when I have asked those questions, but I appreciate it. It is not your responsibility but it something we face.

I am not in the health industry; I am not in the coal industry. But the job that has been thrown to me is to try to make a decision. You hear the things that we are challenged with, the remarks earlier today that this is a jihad. That kind of incendiary language has no place in this. This is why America is rejecting the discourse here we have in Congress when those kinds of comments are getting made. I don't want us to be portrayed as being pro-pollution, that I am polluting the water, I am putting mercury in the water and the air, that I am trying to kill children. I want us to have an open dialog where we can have these kinds of discussion because that is the decision we have to make, not emotional but a scientific basis. I happen to be an engineer in Congress, and I hope we can use our science to make these decisions rather than emotion.

Thank you very much for your testimony.

Mr. WELLINGHOFF. Thank you.

Mr. WHITFIELD. Thank you.

At this time I recognize the gentleman from California, Mr. Waxman.

Mr. WAXMAN. Thank you, Mr. Chairman, and I want to thank Mr. McKinley for his last comments. I fully agree with him and I look forward to working with him to reduce some of the rhetoric and see if we can work together.

Chairman Wellinghoff, some members of the committee and several of the witnesses in their written testimony are citing the FERC's staff's informal assessment of the potential impacts of EPA rules as evidence that 81 gigawatts of coal generation is likely or very likely to retire. It is important for members to understand that the FERC staff is trying to do, how they did it, and the serious limitations of the informal assessment.

The FERC staff who worked on this informal assessment briefed the committee staff. They told our staff that the informal assessment was intended as a back-of-the-envelope calculation to produce a ballpark estimate of potential retirement that could result from the EPA's rules. They said it was never intended as information for the FERC commissioners or to be relied on for decision-making.

Chairman Wellinghoff, does this description match your understanding?

Mr. WELLINGHOFF. It does, and I actually mentioned earlier that that number should in no way be used as a planning number. The planning determinations will be those that will be ultimately done by the planning authorities and so all the range of numbers that we have thrown out there and floating around out here are really irrelevant. What is really relevant is the actual work that each planning authority will do, and you will hear from a couple in the next panel. The actual work that the planning authorities will do and they do on an ongoing basis, it is not that they are going to start it all of a sudden because EPA has done this. They have been doing it for years and year and years. We have now put in place some rules that actually require them to incorporate into those planning activities considerations of things like federal and State regulations that in fact could impact their planning, and many of them have been doing it already despite our rules. We wanted to make sure that it was something that was actually being done. And so we have given them that tool and they are now—I expect fully that they will use it.

Mr. WAXMAN. I appreciate your putting that in perspective. The FERC staff started this project in the summer of 2010 before EPA had proposed or finalized certain rules so the FERC staff made assumptions about what the EPA rules would require.

Chairman Wellinghoff, did these assumptions turn out to be accurate?

Mr. WELLINGHOFF. No, they weren't accurate.

Mr. WAXMAN. For example, FERC staff assumed that EPA would require closed-loop cooling systems under one rule but EPA's proposed rule did not require this approach. FERC staff explained how they actually did their assessment. They relied on publicly available information about existing coal plants. They came up with factors they thought could affect the cost of compliance at these plants and then assigned those factors subjective weights. For example, if a plant has no mercury controls, that was worth two-tenths of a point. If it was an anti-coal State, whatever that means, it got another tenth of a point. The FERC staff told our staff that this weighting was "completely arbitrary." Then the staff added up all of the weighted factors that applied to a plant and placed the plant in a category such as very likely or unlikely to retire. The total scores that would lead a plant to be placed in one of these categories was also just arbitrarily made up. This description isn't meant as a criticism. The staff was just trying to do a back-of-the-envelope estimate.

Mr. Wellinghoff, is this your understanding how the FERC staff did their informal assessment?

Mr. WELLINGHOFF. They did, and I do want to make clear, it had nothing to do with the level of competency of my staff. They used the information that they had at the time to do a very informal assessment to start discussions with the EPA so then EPA could be better informed about who they needed to talk to in more specificity, that is, the planning authorities with respect to the potential impacts of what they were doing.

Mr. WAXMAN. The first time they did this assessment in July 2010, the estimate was that 81 gigawatts of coal generation were likely or very likely to retire, but as the staff obtained more information about what EPA's rules actually required, later calculations produced lower estimates. In October 2010, the estimate was down to 72 gigawatts. By early 2011, the estimate had dropped to between 54 and 59 gigawatts of likely or very likely retirements. Isn't that right, Mr. Wellinghoff?

Mr. WELLINGHOFF. That is correct. Actually, the February 2011 range is 54 to 59 gigawatts. Again, these are——

Mr. WAXMAN. Let me just, because I am running out of time. Even for these lower estimates, there was no estimated timeframe for retirements. FERC staff never examined how the industry could compensate for any retirements with new generation capacity, retrofits, demand response or energy efficiency measures. To make sure everyone is clear on this point, is the FERC staff informal assessment something that members of the committee or witnesses should be relying on or citing when assessing the potential impacts of EPA's rules?

Mr. WELLINGHOFF. No.

Mr. WAXMAN. Thank you very much, Mr. Chairman.

Mr. WHITFIELD. At this time I recognize the gentleman from Texas, Mr. Barton, for 5 minutes.

Mr. BARTON. Thank you. I was hoping in my absence, Mr. Chairman, that you all worked all this out.

Mr. WHITFIELD. It has been very pleasant.

Mr. BARTON. There is still hope.

My first question to the distinguished chairman of FERC is that several times in answer to questions, you have used the term "irrelevant." Do you consider the FERC staff to be irrelevant?

Mr. WELLINGHOFF. No, sir, I don't.

Mr. BARTON. Do you assume them to be honest, hardworking professionals who when asked to do something give it their best effort?

Mr. WELLINGHOFF. Yes, sir, I do.

Mr. BARTON. OK. I agree with you, that to my knowledge the FERC staff is hardworking and very professional. In fact, I would say of all the agencies we deal with, the FERC staff is probably the least politically motivated or impacted. They tend to be very straightforward and professional, in my assessment, anyway. Are you aware that we have got a list of 14 different organizations that have looked at the impact of the EPA's rules on the power market and 12 of the 14 are basically in the general range of the FERC staff assessment? Are you aware of that?

Mr. WELLINGHOFF. Yes, and again, I would indicate that those assessments are irrelevant as well, and I am not saying that there is——

Mr. BARTON. There is no assessment that is relevant?

Mr. WELLINGHOFF. There is one, yes. The assessments that will be done by the individual planning authorities like ERCOT in your State, for example, PJM, the other RTOs and the planning authorities, those assessments that the planning authorities conduct are ones that in fact will be most informed at a local level based upon actual data with respect to actual specific resource requirements and resource needs and resource availability within those regions. Those are the critical——

Mr. BARTON. I would respectfully interrupt you, Mr. Chairman, and respectfully disagree with you that I think for whatever reason these groups that have looked at this issue are trying to give it their best estimate, if that is the right term, and I think they are relevant. I think it is odd, to be as mild as possible, that EPA consistently underestimates the impact of their rules, and, you know, I took probability in college, and I would say the probability is that EPA is going to be the most off in terms of realistically estimating what their impact is of all the groups because they have a bias against realistically evaluating their rules. And just in one of the rules that they proposed last year, their analysis, they admitted eventually was only off by a factor of 1,000, which is pretty off.

I want to ask Mr. Moeller, Commissioner Moeller if you share the chairman's assessment about the irrelevancy of these estimates.

Mr. MOELLER. Well, I think the estimates are all informative but I probably share his opinion that what really matters is how they impact operations and reliability at the local level because of the specifics of load pockets and the physics of electricity flow, and I actually thought the FERC staff study was pretty good because it went into a lot of the variable factors. It was an estimate. It was done with what they knew at the time. Things have changed. But I commend our staff for what I thought was a very good document.

Mr. BARTON. I have only got about a minute. My last question, again, back to our distinguished chairman, you state in the letter that you think your organization lacks the data and the tools to fully assess the reliability impact of EPA regulation. What additional tools and data would you need, in your opinion, for the FERC to have that ability?

Mr. WELLINGHOFF. Well, we would have to have the capability of the modeling that is done by all the regional planning authorities, and their modeling is extremely extensive with very sophisticated computer models and lots of computer equipment. PJM alone has 500 employees, I believe, and that is just one planning authority in and of itself. So again, we are not a central planner. We are not set up to be a central planner, and to do that would take a great deal of appropriations from this Congress that I don't think they really want to do.

Mr. BARTON. My time is expired, but is there any reason then that the FERC couldn't send a letter or make a request of the folks that have this modeling capability if you gave them the data sets that they couldn't do the modeling and report back to you? Is that allowed or not allowed?

Mr. WELLINGHOFF. No, they have the data sets. We don't have it. They have it. They do the modeling already all the time, and you will hear from two of them. You will hear from ERCOT and PJM in your next panel.

Mr. BARTON. If the FERC staff under the direction of the Commission were to request certain models be run, then you have the authority to do that and they would have to comply. Is that correct?

Mr. WELLINGHOFF. We could ask them to do modeling. That is correct.

Mr. BARTON. I have got some other questions. If I could have one non-related question. The former chairman of the FERC, Mr. Kelleher, called me this week, and the Department of Energy is floating an idea to give the delegate its authority under the Energy Policy Act to do transmission siting. Under current law, the DOE has to determine the corridor, but once the DOE determines that it is a high-priority, high-impact corridor, then the FERC can put together a plant to site transmission. There is a court case in Virginia that invalidated or at least called into question the ability of the Department of Energy to site these corridors, and the current Secretary is considering delegating his authority under the Energy Policy Act to the FERC. Do you have a position on that, Chairman?

Mr. WELLINGHOFF. Yes, Mr. Barton. I think actually that would be an appropriate delegation. I think it would in fact make the current statute work more efficiently.

Mr. BARTON. Do all the commissioners share the chairman's position on that?

Mr. MOELLER. Congressman, I favor the proposal generally but I had a little bit of an issue with the dual siting track that was part of the details. So generally, yes, some of the specifics I don't fully——

Mr. BARTON. I will follow up with that.

Thank you, Mr. Chairman, because I am the author of that section and I have been asked to take a position on it, and I see both sides of it, so I appreciate the information.

Mr. WHITFIELD. Mr. Olson, you are recognized for 5 minutes.

Mr. OLSON. I thank the chair, and thanks to all the witnesses for coming today, for giving us your expertise and your time, and we are in the home stretch here, so I will get my 5 minutes done here.

My first question is for you, Mr. Moeller, and this may be an understatement, but you seem to view FERC's role in addressing potential impacts of EPA regulations on electric reliability very differently from Mr. Wellinghoff and some of your colleagues at FERC. You note in your testimony that legislation clarifying the role of EPA and FERC in the event of a conflict over air policy electric reliability could be helpful, and my colleague, Mr. Shimkus, showed this graph which illustrates the disparity between EPA and all the other groups that are taking a look at the capacity loss resulting from EPA's power sector rules, and I know this is a small graph here but you all can see this little green line here, the very small one is what EPA's predictions are. FERC is right here, the first line. That is a big disparity.

My question is, is there a conflict between FERC and EPA over any of EPA's new rules affecting the utility companies?

Mr. MOELLER. Well, Congressman, I haven't been involved all of the discussions. There have been staff discussions. Some of the individual commissioners have met with officials from EPA. I have had one such meeting, and I have called for a more open process so that we can discuss the ramifications from a reliability perspective of these rules because there are a number of them. The timelines differ. They will affect different markets differently. For instance, in a Texas market where it is a competitive market, the costs to, say, retrofit a plant cannot be passed on to ratepayers.

They have to be absorbed by shareholders. In another area of the country that is vertically integrated, those costs can be passed on. That is going to make a difference as to the investment decision involved as to whether to keep a plant or not. I just think that the level of detail and the complexity of this Nation's electric system calls for a more open process to determine some of the ramifications of these rules.

Mr. OLSON. Thank you for that answer. I will just kind of follow up on that question, and this would be all for the commissioners. I posed this question to Mr. Joseph McClelland of FERC during his testimony here on May 31st on the grid reliability and infrastructure defense but he was unable to give me an accurate answer, so I will ask again, but I wanted to preface it but since that time I visited the power plant in the district I represent, the WA Parish plant there outside of Meadville, Texas. It is one of the largest power generation plants in the country, the largest one in Texas, obviously. It has four coal generating units, four natural gas generating units, and I was out there talking with them about some of the problems we could face in Texas in the future with this drought, it looks like another El Nino, La Nina effect and, you know, extended heat waves, and I talked to them about we have got the fastest growing population in America. I asked them if they have some plans to cover the generation capacity that they might have to cover, and they do say that they have kind of mothballed two plants there in Texas, two coal-burning plants, that they could bring up online in a couple of weeks if so needed. My question is, if FERC had to require or order a generating unit to operate for reliability purposes and doing so would result in the unit exceeding environmental permit level, would FERC indemnify the operator from any and all agency actions for private citizen lawsuit liability? Commissioner LaFleur, you are first, ma'am.

Ms. LAFLEUR. I don't believe we would indemnify but I think that we would try to work out in advance with the other agencies to make sure that if we ordered a plant to operate that they would not face compliance violations, and I know there also have been legislative proposals, surgical proposals to remove individual liability to individuals for operating in response to a FERC order, and if there is a need for clarity, I would suppose those, but we would certainly try to work out that there was no compliance violation.

Mr. OLSON. Thank you.

Commissioner Norris?

Mr. NORRIS. I believe it is a situation Mr. Spitzer has addressed a couple times during the hearing here, and that is, it is an unfair situation to put a utility company where they have to abide by two different agencies' rules, FERC's and EPA's, and while I don't know if we can—we can't protect them from that agency suing them. I think there is some proposed legislation—I can't think of the name of it—to address that situation and I think it would be a positive outcome.

Mr. OLSON. Mr. Spitzer, I am sorry I didn't hear our testimony before, sir, but it sounds like, did Commissioner Norris give an accurate summary of your feelings?

Mr. SPITZER. Yes, correct, Congressman. In my testimony, I discussed a safety valve proposal proposed by some of the entities including ERCOT, and we can supply you with this. It is comments they filed before EPA on May 3, 2011, that I would support that resolves this potential Hobson's choice of complying with—violating either an EPA rule or FERC reliability standard, and I suggest that proposal could solve that problem.

Mr. OLSON. Commissioner Moeller?

Mr. MOELLER. I agree. It is a problem, and I think if you talk to entities who had to face this situation in the past, they won't do it again because it is too risky having two agencies, choosing to violate one set of rules or the other.

Mr. OLSON. That was my experience with Parish. They are willing to do it but they won't do it if they can't be covered legally.

And Mr. Chairman, I am sorry, last but certainly not least.

Mr. WELLINGHOFF. Thank you, and I agree with the safety valve solution that Commissioner Spitzer discussed. I think that is a remedy that in fact would take care of the issue.

Mr. OLSON. Thank you, Mr. Chairman.

Mr. WHITFIELD. Mr. Terry, you are recognized for 5 minutes.

Mr. TERRY. Thank you, Mr. Chairman.

To start off, I have three documents I would like to enter into the record.

Mr. WHITFIELD. Without objection.

Mr. TERRY. The first is a letter from our Governor to Administrator Jackson expressing his concerns with the number and substance of the regulations. The second is an article from the Grand Island Independent discussing the now-expected closure of the Grand Island coal-fired plant as a result of CSAPR. And the last is an article from the Lincoln Journal Star that just ran yesterday regarding the same issue. Thank you, Mr. Chairman.

[The information follows:]

STATE OF NEBRASKA

Dave Heineman
Governor

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September 8, 2011

Lisa Jackson, Administrator
U.S. Environmental Protection Agency
USEPA Headquarters
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, DC 20460

Dear Administrator Jackson:

I am writing to express my concerns with a number of air quality regulations issued or proposed by the U.S. Environmental Protection Agency and the negative impact these regulations will have on Nebraska. I support the goals of clean air and a protected environment. However, there must be a balance between what needs to be done to protect the environment and what costs Nebraska's economy can absorb. As with the recent ozone retraction by President Obama, there needs to be a reexamination to reduce the regulatory burden and uncertainty on states and industry.

On August 8, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) that will significantly impact the utilities in Nebraska and the citizens they serve. Of the 28 states that will be subject to CSAPR starting January 1, 2012, all but four, including Nebraska, were subject to the Clean Air Interstate Rule (CAIR) prior to CSAPR. The other 24 states and their utility companies have had since the original 2005 CAIR rule to make preparations for compliance with this rule. Until just last month when CSAPR was finalized, Nebraska believed that compliance with interstate transport rules would be reasonable to achieve. However, upon reviewing the final rule, Nebraska's utilities have serious concerns over the ability to comply with a 2012 compliance deadline.

The stringency of the CSAPR program is shocking, and now the Nebraska facilities are thoroughly examining and evaluating the impacts of this rule on their sources. Specifically, the nitrogen oxide emissions budget in the final rule is far less than what was proposed in July 2010 and in the subsequent notices of data availability in early 2011. The utilities have quickly begun planning for the installation of controls. It is very unlikely, even with the controls that could feasibly be installed during the calendar year 2012, that the State of Nebraska can meet the assurance levels for NOx. Most of the controls will take three to five years to install. Nebraska's public power companies need time to budget, finance, and design the controls.

Lisa Jackson, Administrator
U.S. Environmental Protection Agency
September 8, 2011
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I am requesting an additional three years to comply with this rule. You have the authority under Section 110(k)(6) of the Clean Air Act to make corrections to federal actions. Therefore, I am formally requesting you exercise your authority to provide the State of Nebraska and its utilities this additional time.

The Utility MACT, which has not yet been finalized, would require costly additional controls by 2015. The retrofitting of power plants on such a tight timeframe, in concert with the other air quality rules, is excessive. The annualized costs to comply for Nebraska's two largest companies are estimated to be in excess of $150 million per year. The capital costs are estimated to be over $1 billion for just one company. Nebraska, as a western state, will yield minimal benefits from the Utility MACT rule. The EPA estimates that western states will benefit approximately only 2% of what eastern states will.

I am concerned about the timing and the ability of Nebraska's public power companies to continue providing affordable reliable power to the citizens of Nebraska. Nebraska's not-for-profit, publicly owned power companies are expecting to reduce capacity significantly in order to try to comply with the promulgated rules. To meet future demands, power may need to come from elsewhere on the grid. Nebraska has a long history of meeting its own power needs without having to import much from outside the state.

Nebraska's rural areas face many challenges. Since 2000, 69 of our 93 counties have experienced a decline in population, while our urban areas have experienced an increasing population. Both factors create unique dynamics that the power companies must be ready to serve and sustain. Nebraskans support our public power system as the best way of ensuring low-cost, reliable electricity to our citizens, communities and industries. For one sector to be facing so many costly compliance measures to implement over such a short period of time is unfair.

These examples of excessive regulations are too costly and onerous on the power generating industry. Nebraska is totally publicly owned power, and Nebraska's families will experience increased rates as a direct result of these actions. It will hamper economic development. I am asking you to carefully evaluate the cost of these rules separately and aggregately. For Nebraska businesses, communities and agriculture, the cost of these rules simply outweighs the benefits. Thank you.

Sincerely,

Dave Heineman

Dave Heineman
Governor

theindependent.com

News > Local

New EPA regulations could be costly to G.I. power consumers

Print Page

By Robert Pore

robert.pore@theindependent.com

Published: Wednesday, September 7, 2011 10:08 PM CDT

New U.S. Environmental Protection Agency clean air regulations, which will be implemented on Jan. 1, 2012, could impact Nebraska's energy industry, causing possible power plant closures, employee layoffs and increase power rates.

That's according to a group of Nebraska energy officials who met with state Attorney General Jon Bruning Wednesday in Grand Island at what was called an "EPA Summitt."

At issue are additional Clean Air Act regulations, announced in July by the EPA, designed to "slash hundreds of thousands of tons of smokestack emissions that travel long distances through the air leading to soot and smog, threatening the health of hundreds of millions of Americans living downwind."

What the EPA announced was the Cross-State Air Pollution Rule, which the agency said will achieve up to $280 million in annual benefits through cleaner air coming from the nation's coal powered energy plants. Nebraska is one of 27 states in the eastern half of the country that the new rules will impact. The EPA said the new rules will impact 240 million Americans.

At the heart of the new regulations are reductions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from power plants, which the EPA said travels across state lines, contributing to harmful levels of smog (ground-level ozone) and soot (fine particles), which they said are scientifically linked to widespread illnesses and premature deaths.

Under the new regulations, EPA said that by 2014, the rule and other state and EPA actions will reduce sulfur dioxide by 73 percent from 2005 levels and nitrogen oxide emissions by 54 percent.

The new Cross-State Air Pollution Rule, the EPA said, replaces and strengthens the 2005 Clean Air Interstate Rule (CAIR), which the U.S. Court of Appeals for the D.C. Circuit ordered EPA to revise in 2008. The court allowed CAIR to remain in place temporarily while EPA worked to finalize its replacement rule.

According to the EPA, the new regulations are estimated to cost $800 million in 2014, plus about $1.6 billion per year in capital investments, which the EPA said are already under way from Clean Air Interstate Rule, the previous rule from 2005.

The EPA also acknowledged jobs could be lost as the result of the new regulations. They also estimate that by 2014, the average monthly household electricity bill will increase by 1 percent and natural gas prices will increase less than 1 percent.

Energy officials, though, estimate that rules would increase energy costs by 5 to 10 percent, including natural gas, which would be used as a alternative to coal to produce energy. That would create extra demand for natural gas, increasing costs.

Also, some of the older coal plants may have to shut down to refit themselves to meet the new regulations or close altogether.

Attending the summit was Tim Luchsinger, Grand Island utility manager. Grand Island has its own coal-powered energy plant, along with one natural gas unit. Luchsinger said Grand Island is planning to spend $4 million in the next year for capital improvements to the city's Platte Generating Station to comply with the new EPA rule.

"We are anticipating spending another $1.3 (million) to $1.5 million in fuel costs on natural gas at our Burdick Station next year," he said.

Luchsinger said the reason for the increased used of natural gas to generate power is because of the cap on emission on the Platte Generating Station because of the new EPA regulations.

Even though Grand Island uses coal with a low sulphur content from Wyoming, Luchsinger said they will have to make major renovations to the city's coal plant to meet the new regulations.

"In the next three years, we will have to add probably another $35 (million) to $40 million worth of equipmant to comply with the new regulations," he said.

At first, Luchsinger said, Grand Island consumers will see a "slight" increase on their energy bill because of the cost of burning natural gas.

"There will also be some impact because traditionally we have been able to sell extra power to other utilities," he said. "We are going to be limited on that now. So, the extra power that we sell, of course, comes back to the rate payers. But it may be another several years before we are able to do that again."

That could cost the city between $3.5 million to $4 million in lost power sales, Luchsinger said.

Luchsinger said the city was caught by surprise by the new EPA regulations "as they capped our emissions a lot lower than what we expected."

"What will impact us the most is that we are seeing a 40 percent reduction in the nitrogen oxide allowances we thought we were going to get," he said. "That is going to be the key to driving our capacity limit."

Luchsinger said the utility department's cash reserve will keep the financial bite to consumers down temporarily, but once the major part of the new regulations take effect in 2014 and the capital improvements that will need to be made to be in compliance, "we are uncertain whether that will be a rate increase or if we can do some refinancing with our existing debt."

Bruning, who organized the summit, said he is planning to work with other state attorneys general impacted by the new EPA rules to have to new regulations delayed or revised because of the potential impact it will have on consumers and utility companies.

He called the regulations "yet another in a long line of EPA encroachments on state's sovereignty as the EPA has continually told the states where it should make the air clean."

"Here in Nebraska," he said, "we don't want EPA guidance or need EPA guidance on how to do that."

While the EPA regulations are designed to take accountability of states when it concerns pollutants they generate going across state lines and impacting people downwind, Bruning said Nebraska's air is clean now.

"The EPA is asking us to make it yet cleaner," he said. "What the EPA is asking us to do -- to make the air yet cleaner -- is unnecessary, as the air is already clean. So the EPA is continuing to make the state to find infinite gradations of cleanliness that cost more money than they are worth."

Mayors from Grand Island, Hastings and Fremont were also at the meeting. Each of those cities has its own coal power-generating facility, for which Bruning said the new EPA regulations will cost them "tens of millions of dollars each."

"So instead of the city of Grand Island deciding on how to spend $20 (million) to $30 million, the EPA is making that decision for you," he said.

Attending the summit was Keith Olsen, president of the Nebraska Farm Bureau,

"Our concern is if power plants that now run on coal are forced to shut down or convert over to natural gas, that could cause an increase demand on natural gas," Olsen said.

He said natural gas is important to agriculture, especially in the manufacturing of fertilizer.

"We are concerned on what impact that would have on our production costs, but we are also concerned about what the increase in electrical rates would do to the number of irrigators that use electricity to power their pumps," Olsen said.

Also attending the summit was Tim Burke, vice president for customer service and public affairs for the Omaha Public Power District.

Energy generated by coal plants provides 70 to 75 percent of Nebraska's needs, with natural gas, wind and nuclear energy providing the remaining percentage.

Burke said that for Nebraska, as the regulations were originally conceived under the Clean Air Interstate Rule, it had "very little impact" on the amount of toxic pollutants that had to be cleaned from the emissions from state coal plants.

"But the rule that came out this summer, we saw almost twice the impact that were originally identified," Burke said.

Also a concern to Burke is the very short time frame power companies would have to implement the new environmental regulations. Because Nebraska energy officials believed the new rules would have little impact on the state as originally conceived until the new regulations came out in July, they did little to plan for the demands of the new regulations on state power plants. That put them behind, and Burke said catching up under the short time frame demanded by the new regulations would be costly to Nebraska power plants.

"It is a very short time frame for us to put those implementation plans in place, he said. "Therefore, it is going to be a higher cost, a shorter time frame that will impact any pricing of any changes we need to make."

Also, he said, it will impact Nebraska energy consumers.

Because of Nebraska's public power system, those costs can't be passed to shareholders because "our shareholders are our customer-owners and the impacts will be pretty significant for all of consumers and business owners," he said.

Burke said OPPD is evaluating the impact of the new EPA regulations. He said a number of scenarios are being looked at, including shutting down a number of small, older coal generating plants.

Burke also said that OPPD could be looking at a possible 4 percent cost increase to consumers in implementing the new rules, though that would vary among public power districts.

LINCOLN JOURNAL STAR
JournalStar.com

New EPA rules for coal plants could cost millions; lawsuit in works by attorney general

By ALGIS J. LAUKAITIS / Lincoln Journal Star | Posted: Monday, September 12, 2011 11:55 pm

Nebraska utilities could be forced to spend millions, reduce electrical generation and raise electric rates to comply with new a federal regulation governing air pollution from coal plants.

Officials from several Nebraska utilities said they were caught off guard by the proposed regulation, both in its timing and the emission limits, which are more stringent than those proposed earlier by the U.S. Environmental Protection Agency.

"This could be expensive. It could be very expensive. We know that, but we don't know exactly how expensive it's going to be," said Mike Jones of the Omaha Public Power District.

Fremont, for example, may have to spend as much as $35 million over the next five years to meet the new emission standards at its city-owned plant, said Utilities Department Manager Derril Marshall.

Marshall said Fremont also may have to cut power production to near 2009 levels and raise rates by at least 8 percent in each of the next two years.

Representatives from OPPD, the Nebraska Public Power District, the cities of Fremont, Grand Island and Hastings and other utilities met with Nebraska Attorney General Jon Bruning last week to discuss their concerns over the regulation -- especially its timing.

"It was a brainstorming session to see if there was any legal action that could be used to halt or postpone the regulation that goes into effect next year," said Tim Luchsinger, director of utilities for Grand Island.

The Cross-State Air Pollution Rule, announced in July and set to go into effect Jan. 1, cuts allowable emissions of sulfur dioxide and nitrogen oxides, the gases that cause acid rain. EPA says the new standards will significantly improve air quality by reducing power plant emissions in 27 states.

Meanwhile, Bruning is working on a lawsuit to give Nebraska utilities breathing room to comply. A Texas utility already has filed a lawsuit.

"The attorney general's office is working to protect Nebraska power producers and consumers from this costly federal overreach," said Bruning spokeswoman Shannon Kingery. "We anticipate the suit will be filed in the coming months."

Luminant, a leading Texas utility, announced Monday it will close power plants and lay off about 500 workers as a result of what it called the "unrealistic deadline" of the new rule.

Marvin Schultes, manager of Hastings Utilities, said: "It's a very non-achievable deadline to have this compliance by January. There's no way we can get this implemented by then."

Under the new regulation, Grand Island, which has two power plants fired by coal and natural gas, would have to reduce nitrogen oxide emissions by 40 percent, Luchsinger said.

"If we could have had another year, it would have allowed us to get the proper controls in place so it would not affect our operation," he said.

Grand Island plans to spend about $4 million to install new emission-control equipment, which could not be done until October 2012, Luchsinger said. The city also plans to spend $1.3 million more in extra fuel costs.

Lincoln Electric System and NPPD officials are working on how to best comply with the new regulation, said LES Vice President Shelley Sahling-Zart.

Laramie River Station in Wyoming, partially owned by LES, is not affected by the new regulation, but LES does buy power from Sheldon Station and Gerald Gentleman Station, two coal plants owned by NPPD.

"With the significant changes, it's challenging," said Joe Citta, environmental manager for NPPD.

Citta said the earlier regulation proposed by EPA was "fairly manageable." But the final regulation released this summer is forcing NPPD and other Nebraska utilities to take more severe action to meet the new emission standards.

In July, the NPPD Board authorized spending about $35.5 million on new low-nitrogen oxide burners at its Gerald Gentleman power plant near Sutherland.

OPPD is considering shutting down some of its older coal plants, installing new technology to reduce sulfur dioxide emissions, converting coal plants to natural gas, reducing wholesale power sales, and boosting rates by up to 4 percent, Jones said. No decisions have been made.

Mr. TERRY. It is interesting, I know that this issue has been beat to death, but just as a comment, I thought one of FERC's responsibilities was gathering data and providing models so that entities could make the right decisions, that FERC could make the right decisions, so learning that that is—you don't have the data or you don't have the modeling techniques, and I am kind of confused why you have 120 employees in a sub-agency or sub-department called modeling. So Mr. Chairman, I think we have an area that we can save money. We should provide that information to the chairman who is part of the super committee. I don't think those 120 employees—I don't know what they do but they obviously aren't doing what the title says, so we could probably save money by eliminating that.

Next, getting back to the issue of the news stories and our State Attorney General, who hosted a regional event based on the CSAPR rule, this newest version certainly is more stringent than the proposed rule, the Clean Air Transport Rule, so as CSAPR becomes effective in 3–1/2 months—and this is for Mr. Wellinghoff and Mr. Moeller, and we will let Mr. Wellinghoff, the chairman, be first. As CSAPR becomes effective in just 3–1/2 months, are you concerned that States like Nebraska may not have enough time to adequately prepare for CSAPR's substantial increased requirements?

Mr. WELLINGHOFF. Congressman Terry, thank you. I would first clarify your previous discussion. We don't have any division called modeling so I am not sure where you are getting that information from.

But with respect to the CSAPR rule, I believe again that the planning authority that would encompass Nebraska and the State commissioners in Nebraska as well ultimately would have full authority and ability with respect to their modeling capabilities and their resource planning capabilities to plan for these contingencies.

Mr. TERRY. You are right, and I should have said the title of it correctly but I think the one that we can eliminate is the Office of Electric Reliability.

Mr. MOELLER. Congressman, to answer your question, yes, I am concerned because of the timeline of CSAPR and I think you will hear an articulate description of Texas's concerned from the ERCOT representative on the next panel.

Mr. TERRY. Thank you.

Now, hearing those answers then, would it be justified in your opinion to delay the implementation of this rule so the States and entities can have a better grasp of its impact, Mr. Wellinghoff?

Mr. WELLINGHOFF. I do not believe it to be appropriate to delay the rule.

Mr. MOELLER. I frankly don't know the implications enough to know where it is worth delaying or not but I know I would like to be a lot more comfortable about the reliability implications of it.

Mr. TERRY. Thank you.

Mr. WHITFIELD. Thank you.

At this time I recognize the gentleman, Mr. Gardner from Colorado, for 5 minutes.

Mr. GARDNER. Thank you, Mr. Chairman, and thank you for joining us today.

Commissioner Norris, you stated in your testimony that you believe, and this is a quote, you believe that the "EPA had adequately addressed reliability concerns." You base this conclusion not on FERC's own analysis but various studies, in your words, "numerous studies by multiple entities that attempt to assess the reliability impact of EPA's proposed and final regulations." You have talked about those and you claim that you found those publicly available assessments and analyses the most informative for reaching your conclusions. Specifically, you cite in your testimony reports done by, amongst other, the Bipartisan Policy Center, M.J. Bradley and Associates.

Mr. Norris, I don't think any of those organizations work for FERC or work within FERC but yet you are relying upon them and you are statutorily tasked with the responsibility of ensuring the reliability of the bulk power system. Do you believe, do you agree with members of this committee that perhaps FERC should be—that we should be concerned that a commissioner of FERC, the agency that has a prominent role in assuring reliability of the grid, is basing conclusions with respect to EPA's power sector rules on reports completed not by FERC but by outside interest groups with zero accountability to FERC or the American people?

Mr. NORRIS. Let me start with saying I think those reports, they told us some consistent feedback on the situation. One is that there is not likely to be a resource adequacy problem nationwide. We have supplies or we can build supplies or build generation in time to address the overall generation needs of this country. I think that is consistent throughout all those reports. I think there are a lot of very knowledgeable folks of our electric system that work on those reports and provide information that I found valuable. I like to seek outside input when I come to a conclusion, and I did extensive research and reading multiple reports. I point at those as the most informative, and I think they represent a cross-section. There are differences in those reports but the consistent theme I saw in them was, we can meet our Nation's electric supply needs under the many different scenarios run.

Secondly, the other consistent thing in that report as I stated earlier is the natural gas impact is having on the marketplace in general in terms of retiring old, inefficient plants. So, yes, I rely on those reports and I will continue to rely on those and other knowledgeable reports and how the proposed EPA rules may impact our system.

Mr. GARDNER. Do you think it is wise to rely on outside reports so heavily, though?

Mr. NORRIS. Well, I probably erred in not putting our own report in there because I read that extensively as well. Yes.

Mr. GARDNER. And a question based on Ms. LaFleur's testimony. She stated in her second paragraph, third paragraph of her opening statement, "Although not all these regulations are final, I believe it is important to consider them as a package when assessing their potential effect on reliability," talking about the effect of the rules together. There has been legislation introduced in Congress that talks about the effect of EPA regulations on energy costs and prices. Do you think that those ought to be looked at together as well in addition to reliability, what it does for cost? And Mr. Moeller, I will start with you.

Mr. MOELLER. Well, it is kind of society's choice as to the costs of health regulations versus the increases in electricity prices, but I think most studies would indicate that prices are going to rise and there is a variety of studies as to how much they will rise in different areas, depending on how dependent they are on certain fuels, particularly coals, but——

Mr. GARDNER. Do we have a mechanism to look at the costs cumulatively, as Ms. LaFleur says, on reliability, just as we do on reliability that she is suggesting that we do?

Mr. MOELLER. Yes.

Mr. GARDNER. Mr. Spitzer?

Mr. SPITZER. Mr. Chairman, Congressman, my view, and this goes back to my serve in the State legislature and at the State commissioner and now at FERC, is government is about balancing competing interests, and you have air quality, health issues balanced against the costs and the Congress doubtless considers that as does EPA, as do the State commissions. In the narrow issue of reliability, that is why the aggregate numbers certainly have an impact on wholesale power prices but there are many other variables with wholesale power. The natural gas revolution that I discussed earlier, concern over nuclear power in the wake of Fukushima may have an impact on our fuel supply.

Mr. GARDNER. Should we, though, have a system in place that takes a look at the cost of regulations comprehensively, cumulatively as they are added to our energy sector?

Mr. SPITZER. I hope this is not gratuitous, but I think government at all levels has an obligation to continually revisit the circumstances which change over time. FERC has a serious mission and all five of us are very serious about the authority granted by Congress in 2005 in Section 215 of the Federal Power Act, which is why we are so zealous with regard to our space in terms of the reliability.

Mr. GARDNER. Ms. LaFleur, would you take that same approach that you take on reliability to the cost that regulations have on energy production?

Ms. LAFLEUR. Well, the point of my comment, I think, was that the only way to really assess reliability is at the local level. You know, my former Massachusetts fellow citizen in this body, Tip O'Neill, said all politics is local. I would say all reliability is local. So in order for a plant to decide whether to stay open, they can't just look at MACT, they have to look at the transport rule and they have to look at the cost of retrofitting totally. I think that for a plant deciding whether to stay open, they should look at all the costs, whether some kind of macroanalysis of all the costs would be meaningful across the country, I think you would get the same kind of modeling issues that we have for all the macroanalyses that go from, you know, 30 to 80 of how many retirements there would be because the costs will depend on what decisions people make how to comply. So I am not sure I think a big macro cost number is going to be meaningful but I think the individual units have to look at the costs.

Mr. WHITFIELD. The gentleman's time has expired. I recognize Mr. Markey for 5 minutes.

Mr. MARKEY. Thank you, Mr. Chairman.

Mr. Chairman, thank you all for being here. How many of you believe that the threat of a cyber attack on the electric grid is the top threat to electric reliability in our country? Is that your belief, Mr. Wellinghoff?

Mr. WELLINGHOFF. I certainly believe that both cyber and physical security are major issues that we need to be concerned with respect to maintaining our electric grid.

Mr. MARKEY. Is it at the top of your list of concerns?

Mr. WELLINGHOFF. Yes.

Mr. MARKEY. Are there any on the panel that do not have that at the top of their list of concerns? No. So you all have that.

Well, I agree with you, and last year this committee unanimously passed the GRID Act, which was co-authored by myself and Mr. Upton, and that bill gave the FERC the authority to quickly issue grid security orders or rules if vulnerabilities have not been adequately addressed through existing reliability standards or other industry efforts. Do you believe that giving FERC this authority would increase America's ability to appropriately respond to threats and vulnerabilities facing our electric grid, Mr. Chairman?

Mr. WELLINGHOFF. Yes, I do, Mr. Markey.

Mr. MARKEY. Yes or no, each member.

Mr. MOELLER. I have come around to support FERC having more authority.

Mr. MARKEY. Thank you.

Yes?

Mr. SPITZER. Yes, Congressman.

Mr. NORRIS. Yes. I would give you a little bit more if you would take it.

Mr. MARKEY. Very briefly.

Mr. NORRIS. OK. That is because the cyber attacks have orders of magnitude on reliability. It can wipe out a whole interconnect. We are talking about in this situation very localized reliability situations that we currently have the tools to deal with but we need the tool you are talking about to deal with cybersecurity.

Mr. MARKEY. And the FERC needs that authority. Do you all agree with that?

Mr. WELLINGHOFF. Yes.

Mr. MARKEY. OK, yes.

Ms. LAFLEUR. Yes, I do.

Mr. MARKEY. Based on what industry has done thus far, do you think that industry is likely to quick move, Mr. Chairman, to take all necessary steps to secure itself if FERC is not given the authority contained in last year's GRID Act?

Mr. WELLINGHOFF. Well, just to be a little fair to industry, they are setting up a group called the Transmission Forum and they are trying to move, but I don't know how quickly they are going to be able to move independently on their own with a voluntary group.

Mr. MARKEY. Do you think that the FERC has to have this authority in order to make sure that the voluntary becomes real? They can work together but in the absence of FERC having that capacity to mandate a solution, do you think it will happen?

Mr. WELLINGHOFF. Yes, they can work together but I do think FERC should have this authority.

Mr. MARKEY. Do you all agree with that? OK. Well, that is very important for us to hear because ultimately it is just not enough in the absence of the FERC having that authority.

Is there a reason to believe that we will be able to solve this problem in the absence of legislation passing, Mr. Wellinghoff?

Mr. WELLINGHOFF. I don't see a solution in the absence of legislation.

Mr. MARKEY. That is very, very helpful to us, so let us just hope that this year we can pass that legislation and then get it passed through the Senate as well, giving that authority.

Now, the argument here today is that we have some kind of tension here between the air quality and air conditioning, and we have to pick one or the other in our country, but let us focus here on the fact that there are already 13 States—Connecticut, New Jersey, Delaware, Illinois, Massachusetts, Maryland, Michigan, Minnesota, Montana, New York, Oregon, Utah and Wisconsin—who have already required their coal-fired plants to remove as much or more of their mercury emissions as has been proposed at the federal level by the EPA and about 70 percent of coal-fired boilers that submitted data to EPA already meet the standards for particulate matter and hydrochloric acid. So it seems that this is possible. In fact, one example, Illinois receives 46 percent of its electricity from its 31 coal-fired power plants and has also reduced its mercury emissions by 90 percent, a level more stringent than EPA's proposal.

Chairman Wellinghoff, have there been any reliability problems in Illinois due to their efforts to take the poison out of the air?

Mr. WELLINGHOFF. To my knowledge, there have not been, and I assume that is because the planning authority that encompasses Illinois has taken this into account when they have done planning.

Mr. MARKEY. Thank you. Now, Massachusetts required an 85 percent reduction in mercury emissions in 2008, a level that is also more stringent than EPA's proposal. Were utilities in Massachusetts able to keep the lights on even thought this standard was being met, Commissioner LaFleur?

Ms. LAFLEUR. Yes, they were, and there is an example in Massachusetts of a plant that they are planning to close right now through gradual planning and transmission reinforcement just a kind of replacement for old plants that we are talking about.

Mr. MARKEY. The technology is there——

Ms. LAFLEUR. Yes.

Mr. MARKEY [continuing]. In an affordable way. Health gets protected. Air conditioning gets protected. All we have here are a certain small number of utilities that are in a sit-down strike against technological progress. We should just continue to keep that in mind.

Thank you, Mr. Chairman.

Mr. WHITFIELD. At this time I recognize the gentleman, Mr. Walden from Oregon.

Mr. WALDEN. Thank you very much, Mr. Chairman. I want to follow up on what my colleague and friend from Massachusetts was talking about because he referenced Oregon, and in the case of the lone coal plant in Oregon, the cost to ratepayers was going to be roughly $520 million, so instead they are closing down that plant over a 10-year frame and will replace it with either two natural gas plants or some other alternative. So when they were trying to address the SOx, NOx, and mercury issues, the cost to ratepayers was so high to meet these requirements that instead they are going to close that plant, which really raises the question about reliability. And Section 215 of the Federal Power Act permits FERC to direct NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system in North America.

And I think what we are trying to get at here, at least I am, is just as we make policy and watch policy being made, do we have a good basis of information upon which to make our decisions, and it strikes me that in the EPA's own rule on whatever page this is, 25,054, it says it is EPA's understanding that FERC and DOE will work with entities whose responsibility it is to ensure an affordable, reliable supply of electricity including State PUCs, RTOs, the NERC to share information and encourage them to begin planning for compliance and reliability as early as possible this effort to identify and respond to any projected local and regional reliability concerns will inform decisions about the timing of the retirements and other compliance strategies to ensure energy reliability, which is what we all want.

Now, Mr. Wellinghoff, so in this initial look at the potential retirement of coal-fired generation, its effect on system reliability preliminary results, it talks in here on page 29 of this handout, which I am sure you are familiar with, that the industry must be directed to openly assess the reliability and adequacy impacts of retirement of at-risk units. Such studies should include frequently response, voltage profile, bulk power loading, stability loss, load probability calculations, deliverability of resources through planning studies.

My question is, given what Mr. Barton just asked about whether FERC had the authority to request the information it needs and wants from the regional transmission organizations, in fact, in the FERC staff presentation, which I think you referred to as irrelevant, there is this slide I just referenced which talks specifically about this information. Have you solicited that information?

Mr. WELLINGHOFF. I want to make very clear that I didn't suggest, Congressman, that the FERC staff presentation was irrelevant. What I said was irrelevant was the 80-gigawatt number would be irrelevant for planning purposes. Let us make it very clear. For planning purposes, what that number is again is a back-of-the-envelope number for the purpose of starting a dialog with EPA as to how EPA can interact with the planning authorities and those planning authorities can ultimately continue to do the work that they have done and will continue to do to ensure that we have a reliable system in the country.

With respect to all those parameters that you referenced in that particular presentation, those planning authorities in fact have been directed by FERC to engage in those activities under Order 890 and under Order 1000. So we specifically with respect to those orders ensure that the planning authorities——

Mr. WALDEN. Related to those EPA rules specifically?

Mr. WELLINGHOFF. Yes. In fact, in Order 1000, we very specifically say that they must consider both federal and State public policies which would include the EPA rules. So yes, we absolutely have done that in Order 1000.

Mr. WALDEN. So you have asked for information, all these points related to these rules?

Mr. WELLINGHOFF. We haven't asked for information. We have directed them to in fact incorporate that information into their planning processes to ultimately conduct their planning processes that in fact when they conduct those planning processes take account for things like the EPA rules.

Mr. WALDEN. Right. So let me try and understand this. So I would think FERC would play a more direct role in this.

Mr. WELLINGHOFF. We don't do central planning, and we don't do planning. It is not our function. You haven't given us that function. We are not planners. The planners are——

Mr. WALDEN. So——

Mr. WELLINGHOFF [continuing]. The specific regional planning authorities——

Mr. WALDEN. So what was the purpose of this preliminary report?

Mr. WELLINGHOFF. The purpose of the preliminary report was to start the dialog with EPA with respect to informing them of the planning activities that the planners conduct and ensure that the planning activity was one that could be well informed by——

Mr. WALDEN. So what has happened——

Mr. WELLINGHOFF [continuing]. The EPA rules.

Mr. WALDEN [continuing]. Since then?

Mr. WELLINGHOFF. What has happened since——

Mr. WALDEN. Why would——

Mr. WELLINGHOFF. We are continuing the dialog with EPA. What has happened is that we are directing EPA to in fact interface directly with the planning authorities like PJM, like ERCOT and others, and to provide them all the data that EPA has to help those planning authorities have an adequate handle on what they need to do to do their job to ensure reliability in this country.

Mr. WALDEN. But I thought your testimony said you basically stopped that effort in May.

Mr. WELLINGHOFF. We haven't stopped the effort of talking to EPA, no.

Mr. WALDEN. All right. My time has expired, Mr. Chairman.

Mr. WHITFIELD. I think everyone has had the opportunity to ask questions, and I want to thank the commissioners for taking time to be with us this morning. I know it has been a rather lengthy session, and the next time you come we will try to be a little more——

Mr. RUSH. Mr. Chairman?

Mr. WHITFIELD. Yes.

Mr. RUSH. Mr. Chairman, it seems to me that, and I wanted to say this in the presence of the commissioners here, that this subcommittee should hold a hearing on the Cross-State Air Pollution Rule specifically. We have not done so yet, and I believe that the conversation that we have heard today really merits such a hearing and I would just ask on the record that we do conduct a hearing on the Cross-State Air Pollution Rule.

Mr. WHITFIELD. Well, thank you very much.

Mr. WALDEN. Mr. Chairman?

Mr. WHITFIELD. Yes?

Mr. WALDEN. Can I just—because I have got a conflict going on here on an answer. Can I ask just——

Mr. WHITFIELD. Sure.

Mr. WALDEN. Mr. Wellinghoff, in your submission back to the subcommittee on a question that was asked about continuing communications, your answer, and I am quoting here, is "Other than the discussion between Assistant Administrator McCarthy and I on August 26th, which was described in supplemental responses to the committee's May 9th information request, communications between FERC staff and EPA staff have not been ongoing." That is your answer to our question. Now, that is——

Mr. WELLINGHOFF. Not ongoing, that is true, but that doesn't mean they are not continuing. I mean——

Mr. WALDEN. Oh, I have to get a Webster's out.

Mr. WELLINGHOFF. Since that period of time that we discussed there, there was no—nothing happened there in that particular period of time. I had a conversation with Lisa Jackson yesterday. I mean, we continue to have discussions all the time.

Mr. WALDEN. OK. So I have to look up ongoing versus continuing. I am confused. I understand based on your written answer here that the staff have not been going, conversations have not been ongoing, communication between FERC staff and EPA staff have not been ongoing is your written response here.

Mr. WELLINGHOFF. Congressman, perhaps that was a poor choice of words. It meant during that—in that interim period of time, there were no other meetings. That is simply all that meant.

Mr. WHITFIELD. I am also going to enter into the record without any objections a statement from the North American Electric Reliability Corporation who wanted to testify but they were unable to do so, so they submitted their testimony for the record.

[The information follows:]

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Gerry W. Cauley
President and CEO

September 13, 2011

Honorable Fred Upton, Chair
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Bldg
Washington, D.C. 20515

Honorable Ed Whitfield, Chair
Subcommittee on Energy and Air Quality
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Bldg
Washington, D.C. 20515

Dear Chairmen:

At your request, I am submitting the enclosed statement for the record for the Subcommittee on Energy and Power's hearing on "The American Energy Initiative" on Wednesday, September 14, 2011, at 9:00 a.m. The hearing's focus is on the impacts of the Environmental Protection Agency's new and proposed power sector regulations on electric reliability.

On April 7 of this year, I testified before this Subcommittee on NERC's October 2010 report titled, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. The focus of this October 2010 report was to quantify the potential impacts of pending EPA regulations on future electric supply adequacy and identify considerations needed to maintain bulk power system reliability. My testimony addressed key findings of this assessment with respect to bulk power system reliability.

Through the study's integrated impact analysis, NERC assessed the cumulative effects of multiple regulations on electric power generation. Because more than one regulation may apply to any given power plant, the integrated analysis enabled NERC to complete an economic assessment to measure the potential effects of complying with these regulations, specifically identifying the effect unit retirements and de-rates may have on peak reserve margins in regions around the country. This cumulative impact analysis conforms to the integrated planning methods the industry performs for capacity planning--bulk power system facility owners must address investments to comply with all regulations rather than each regulation in isolation. By determining the aggregate impact of the multiple applicable regulations, the industry can identify economically vulnerable units, make decisions on potential retirements and retrofits, and ultimately acquire additional capacity resources to maintain reliability.

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NERC

To complete this decision making process, the industry must be given enough time to effectively coordinate both retirement and retrofit decisions for existing generation, along with resource acquisition to offset retirements and unit de-rates. Each power plant in the United States has its own unique characteristics. Different areas of the country will be affected more than others; therefore, from a power system planning and wide-area reliability perspective, the geographic location of the most affected units must be well understood. I continue to believe that reliability impacts from EPA rules must be evaluated on a cumulative basis, for that is how the asset owners make their decisions on how to respond to the EPA initiatives.

Thank you for the opportunity to submit this statement for the record. NERC stands ready to assist the subcommittee in this important inquiry.

Respectfully,

Gerry Cauley

Gerry Cauley
President and CEO

cc: Hon. Henry Waxman
Hon. Bobby Rush

Statement for the Record
Gerry Cauley, President and CEO of NERC
U.S. House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy and Power

September 14, 2011

Reference:
NERC 2010 Special Reliability Scenario Assessment:
Potential Resource Adequacy Impacts of U.S. Environmental Regulations
http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

NERC'S Mission and Reliability Assessments

NERC's mission is to ensure the reliability of the bulk power system in North America and promote reliability excellence and accountability. Over the coming ten years, the North American electric industry will face a number of significant reliability issues, especially the unprecedented change in generating resource mix, but also implementation of stricter environmental regulations, deployment of a new model for customer interaction with their energy provider, and increased reliance on smarter grids while we work to secure the grid against growing cybersecurity concerns. Given the broad nature of these changes, government and industry action must be closely coordinated to ensure reliability. By assessing and analyzing historic, current and future conditions, as well as emerging issues affecting bulk power system reliability, NERC develops information vital to being a risk-informed organization and supporting a learning environment for industry to pursue improved reliability performance.

NERC was founded in 1968 to develop voluntary standards for the owners and operators of the bulk power system.[1] In 2007, NERC was designated the Electric Reliability Organization (ERO) by the Federal Energy Regulatory Commission (FERC) in accordance with Section 215 of the Federal Power Act, enacted by the Energy Policy Act of 2005. Following approval by FERC, reliability standards promulgated by NERC became mandatory across the bulk power system. Section 215(g) of the Federal Power Act requires the ERO to conduct periodic assessments of the reliability and adequacy of the bulk power system in North America. Section 802 of NERC's Rules of Procedure[2] outlines the objectives and scope of the Reliability Assessment Program as

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[1] The Bulk Power System is defined as generation and transmission of electricity greater than 100kV, in contrast to the distribution of electricity to homes and businesses at lower voltages.
[2] http://www.nerc.com/page.php?cid=1%7C8%7C169.

well as the parameters for Reliability Assessment Reports, including periodic assessments and special reliability assessments.

The results of the periodic reliability assessments are documented in three regularly published reports: (1) the Long-Term Reliability Assessment ("LTRA") published each fall; (2) the annual summer assessment; and (3) the annual winter assessment. NERC's Reliability Assessments are conducted to provide an independent view of the reliability of the bulk power system, identifying trends, emerging issues, and potential concerns. NERC's projections are based on a bottom-up approach, collecting data and perspectives from grid operators, electric utilities, and other users, owners, and operators of the bulk power system, supplemented by independent analysis and reporting by NERC.

Special Assessments are conducted on a regional, interregional, or interconnection-wide basis as conditions warrant, or as requested by NERC's board or governmental authorities. NERC reliability and technical experts also may initiate special assessments of key reliability issues and their impacts on the reliability of regions, sub regions, or an interconnection (or a portion thereof).

2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations

The *2009 Long-Term Reliability Assessment* noted environmental legislation and regulation as an emerging issue. Accordingly, the NERC Planning Committee[3] directed the Reliability Assessment Subcommittee to complete a special reliability assessment of this

[3] The NERC Planning Committee and Reliability Assessment Subcommittee are made up of U.S. and Canadian industry experts, engineers, and technical advisors with expertise in resource planning and environment regulations representing all sectors of the electric power industry.

regulation and legislation. In July 2010, NERC completed an assessment of the status and bulk power system reliability effects from integrating technologies to address potential climate change initiatives.[4] In October 2010, NERC released a report titled, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.*

The focus of this special reliability assessment was to identify potential outcomes of pending and planned U.S. Environmental Protection Agency (EPA) regulations and quantify potential effects on future resource adequacy (i.e., reductions in Planning Reserve Margins). Additionally, the report was intended to inform NERC's stakeholders, industry leaders, policymakers, regulators, and the public so that sound and informed decisions can be made on resource requirements.

This special assessment reviewed the potential effects of four pending and planned EPA regulations on resource adequacy, based on information and expectations as of the end of October 2010. The four regulations studied individually and in aggregate were:

- ***Clean Water Act – Section 316(b), Cooling Water Intake Structures***--Assumed the retrofit of open-loop cooling systems to closed-loop cooling (addition of cooling towers was assumed in our modeling analysis) and all nuclear plants made the upgrades.
- ***Clean Air Act – Section 112, Utility Air Toxics***--*Title I of the Clean Air Act – National Emission Standards for Hazardous Air Pollutants (NESHAP), or* ***Maximum Achievable Control Technology (MACT) Standards;*** Requires coal-fired plants to reduce their emissions of air toxics, including mercury and acid gases.

[4] *Reliability Assessment of Climate Change Initiatives: Technology Assessment and Scenario Development*, http://www.nerc.com/files/RICCI_2010.pdf, July 2010.

- ***Clean Air Transport Rule (CATR)***--Regulates emissions of SO2 and NOx in Midwestern and Southern states to reduce long-range transport of pollutants contributing to ground-level ozone and fine particle non-attainment issues in downwind states.
- ***Coal Combustion Residuals (CCR)***--CCR would regulate coal-fired power plants currently disposing of more than 130 million tons per year of coal-ash and solid byproducts.

Planning bulk power system resources requires an integrated view, one that addresses the cumulative effects of multiple factors that drive decisions. It is for this reason that NERC assessed the aggregate impacts potentially resulting from water, air and hazardous waste regulations.

Conduct of the Study

The design for the study is important to understand—the assessment results are a snapshot of the future based on sound and transparent engineering and other assumptions where uncertainty exists. The assessment relied on two separate scenario cases (Moderate and Strict) for each rule to provide sensitivities to the assumptions used. The Moderate Case assumes the compliance costs as identified in *Appendix I: Assessment Methods* and *Appendix II: Environmental Regulations*. The Strict Case scenarios reflect the coupled effects of higher compliance costs with more stringent requirements for the proposed rules (i.e., stricter emission standards and exclusion of government extensions). As the EPA rules were not all yet final, the Moderate Case and the Strict Case provided sensitivities based on expert judgment and reasonable assumptions to provide information as to the difference in possible outcomes from the potential EPA rules. Further, we assessed each regulation individually and in combination to determine the cumulative effects on resource plans. NERC then calculated the amount of capacity reductions due to accelerated unit retirements and increased station load needed to power additional environmental controls for the years 2013, 2015, and 2018, based on demand and generation projects from NERC's *2009 Long-Term Reliability Assessment.*

2010 Study Results

The results of the special assessment can be summarized in three key considerations: timing, tools and coordination:

- The timing of industry's obligations for compliance with environmental regulations is the most important consideration. The pace and stringency of these environmental regulations should take into consideration the overall cumulative risk to the bulk power system. Reliability will be a function of the timing associated with regulatory compliance deadlines. The industry needs both time and certainty to act and make informed decisions.
- NERC identified a number of tools the industry and regulators have for mitigating potential reliability impacts resulting from compliance with the environmental regulations assessed in this report. Advancing in-service dates of future generation and implementing more demand response and energy efficiency, as examples, could help alleviate projected capacity losses in severely affected areas. Where organized energy markets exist, price signaling for new resources requirements will be especially important to replace potentially lost capacity in a timely manner. EPA, FERC, the U.S. Department of Energy (DOE) and state utility regulators, both together and separately, should employ the array of tools at their disposal to moderate reliability impacts, including, granting extensions to install emission controls where warranted.

- Industry coordination will be vital to ensure retrofits are completed in a way that does not diminish reliability. Statutory and regulatory safeguards also allow the EPA, the President of the United States, and DOE to extend or waive compliance under certain circumstances. Increased coordination with state regulators will be required to ensure rules can be implemented effectively in order to maintain reliability. Coordinating an industry-wide environmental control retrofit effort creates considerable operational challenges to manage the maintenance schedules of what may be hundreds of retrofits in a short period of time. It will require careful coordinated planning, carried out by the operators throughout the interconnections.

More specifically, the results and key findings of the October 2010 report are as follows:

- **EPA Regulations May Have Significant Impacts on Planning Reserve Margins**
    - For the Strict Case, up to a 78 GW reduction of coal, oil, and gas-fired generation capacity is identified as economically vulnerable during the ten-year period of this scenario. For the Moderate Case, this reduction occurs in 2018; while in the Strict Case, similar reductions occur in 2015.
    - Due to increased demand growth, this reduction in capacity significantly affects projected Planning Reserve Margins for a majority of the NERC Regions and sub regions. Potentially significant reductions in capacity within a five-year period require heightened need for the addition of resources in a short time-period.
    - Overall, impacts on Planning Reserve Margins and the need for more resources is a function of the pace of the proposed EPA rules.

- **Regional Capacity Impacts Will Vary**
    - Capacity reductions are concentrated in six NERC regions: TRE, MRO, NPCC, RFC, SERC and southern WECC. I have attached a map showing the boundaries of the NERC regions to my testimony.
- **Individually, as modeled, the Section 316(b) Cooling Water Intake Structures Rule Would Have the Greatest Potential Impact on Planning Reserve Margins**
    - This rule will apply to 252 GW (1,201 units) of coal, oil steam, and gas steam generating units across the United States, as well as approximately 60 GW of nuclear capacity (approximately a third of all resources in the United States). We assumed all nuclear plants would remain on line in this assessment, though the Oyster Creek nuclear power plant has since announced retirement in 2019.
- **As modeled the Maximum Achievable Control Technology Standards (MACT), Clean Air Transport Rule (CATR), and the Coal Combustion Rule CCR Rules Also Contributed to Reductions in Capacity**
    - The "hard-stop" 2015 compliance deadline applicable to the EPA Utility MACT[5] Rule makes retrofit timing a significant issue and potentially problematic. The increased demand for contractors, materials, and engineering expertise needed to install environmental controls could potentially impede the industry's ability to comply with the rules within the given timeframe.
    - The CATR could have impacts as soon as 2013 with more significant impacts by 2015.

[5] If EPA finalizes the utility MACT rule in November 2011 as currently planned, compliance would be required by November 2014 under Section 112 of the CAA.

- Individually, the CCR Rule is projected to drive the least amount of economically vulnerable units. However, the associated compliance costs of CCR contribute to the cumulative effects shown in the Combined EPA Regulation Scenario.

Study Outreach

As part of developing and "vetting" the assumptions used in the 2010 assessment, NERC gathered input from many sources, including the users, owners and operators of the bulk power system. In addition, NERC also reached out to regulators and policymakers to incorporate additional insights.

NERC and EPA air office staff held discussions on NERC's study beginning five months before the report's release. These contacts included NERC sharing early versions of this special reliability assessment with an EPA staff member focused on the air regulations (MACT and then CATR), discussions and input from an EPA air office staff member on NERC's assumptions and conclusions, and a meeting with EPA staff prior to the release of the report. After the Cross State Air Pollution Rule (CSAPR) rule was finalized, EPA air office staff contacted us to explain the final EPA rules on clean air transport. These discussions focused solely on NERC's draft assessment and on the final CSAPR rule after it was issued in July. NERC was not, throughout all these discussions, requested to review or provide input into EPA work related to its regulations. FERC's Office of Electric Reliability (OER) staff received draft versions of NERC's special reliability assessment both as participants in NERC's Reliability Assessment Subcommittee and also on the Planning and Operating Committees.

Next Steps

NERC issued the *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* in October of 2010. EPA since has issued proposed rules for Utility MACT (now proposed as the Air Toxics Standards for Utilities) and 316(b) (impingement and entrainment of aquatic organisms), and the Cross-State Air Pollution Rule (CSAPR). One of the recommendations in NERC's October 2010 Special Reliability Assessment was for NERC to monitor the EPA regulations studied in that assessment as greater certainty emerges around industry obligations, technologies, timelines, and targets. This ongoing assessment will include impacts to operating reliability and second tier impacts (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) with respect to forthcoming EPA regulations.

Based on events that have occurred since the October Assessment was released, NERC has decided to complete an incremental study, comparing the results from modeling based on updated assumptions and information provided by industry for inclusion in NERC's *2011 Long-Term Reliability Assessment* to be released in early November.

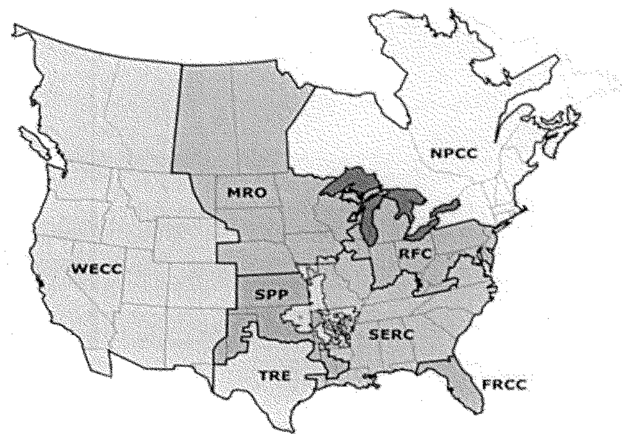
Conclusion

NERC continues to believe that if EPA and industry take the actions recommended in its October 2010 Assessment, the potential reliability implications of these regulations can be managed. Without attention to these matters, we remain concerned about potential reliability implications resulting from reduced reserve margins in certain areas in the United States, constricted timelines for compliance, transmission and operational issues, and the overall uncertainty that exists today on responsibilities and expectations for the electric power industry. NERC continues to believe that reliability impacts from EPA rules must be evaluated on a cumulative basis, for that is how the asset owners make their decisions on how to respond to the EPA initiatives. We look forward to working with EPA and the industry to continue a dialogue on reliability as these proposed rules are considered.

Thank you for your interest in NERC's findings and your attention to bulk power system reliability.

NERC Background

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight Regional Areas shown on the map below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. NERC is currently headquartered in Atlanta with additional offices in Washington, DC.



NERC Regional Entities			
TRE Texas Reliability Entity	**FRCC** Florida Reliability Coordinating Council	**MRO** Midwest Reliability Organization	**NPCC** Northeast Power Coordinating Council, Inc.
RFC Reliability*First* Corporation	**SERC** SERC Reliability Corporation	**SPP** Southwest Power Pool, Incorporated	**WECC** Western Electricity Coordinating Council

Note: *The highlighted area between SPP and SERC denotes overlapping regional area boundaries. For example, some load-serving entities participate in one region and their associated transmission owner/operators in another.*

Mr. WHITFIELD. And once again, thank you all very much for being with us. It is also a great privilege to have the entire Commission here, and we look forward to continued dialog with you as we move forward, so thank you.

At this time I would like to call up the second panel, The Honorable Jeff Davis, who is the Commissioner of the Missouri Public Service Commission; the Honorable Stan Wise, who is Commissioner of the Georgia Public Service Commission; the Honorable Jon McKinney, Commissioner of West Virginia Public Service Commission; and Mr. H.B. Doggett, the President and CEO of Electric Reliability Council of Texas; and then the Honorable Mark Shurtleff, Attorney General of Utah; Mr. John Hanger, President and CEO of Hanger Consulting; and Ms. Sue Tierney, Managing Principal of the Analysis Group. So if you all would take a seat.

Well, thank you all for joining us this morning, and we appreciate your patience. So I am going to call on each one of you to give an opening statement. You will have 5 minutes to do that, and Mr. Davis, we will recognize you first for your opening statement.

STATEMENTS OF JEFF DAVIS, COMMISSIONER, MISSOURI PUBLIC SERVICE COMMISSION; STAN WISE, CHAIRMAN, GEORGIA PUBLIC SERVICE COMMISSION; JON W. MCKINNEY, COMMISSIONER, WEST VIRGINIA PUBLIC SERVICE COMMISSION; MARK L. SHURTLEFF, ATTORNEY GENERAL OF UTAH; H.B. DOGGETT, PRESIDENT AND CEO, ELECTRIC RELIABILITY COUNCIL OF TEXAS; SUSAN F. TIERNEY, MANAGING PRINCIPAL, ANALYSIS GROUP; AND JOHN HANGER, PRESIDENT, HANGER CONSULTING, LLC

STATEMENT OF JEFF DAVIS

Mr. DAVIS. Chairman Whitfield, Ranking Member Rush and members of the committee, thank you for allowing me this opportunity to testify here today. As a Missouri Public Service Commissioner, I am acutely aware of the potential impacts of EPA's pending regulations because it is my job to set the rates on customer bills, and I applaud this committee for reviewing the impacts those regulations are going to have on our citizens and on our Nation's economy.

To summarize my testimony, I feel like my ratepayers are being attacked. Can we keep the lights on? Sure, we will do whatever it takes. That being said, it won't be easy. Nobody knew there was a problem in Arizona or southern California last week until 1.5 million Americans were left in the dark. Reliability is definitely going to be impacted because less generation equals less reliability.

Also, replacing these old coal-fired units will cost more money. They will drive up rates because natural gas plants are still more expensive to operate than coal. Sure, we have got better than 20 percent reserve margins in both the Southwestern Power Pool and MISO footprint but the law of supply and demand says decreased supply increases price and the cumulative effect of these regulations will be to significantly reduce those reserve margins, the capacity, over the next decade by forcing the closure of many coal plants that are smaller than 300 megawatts as well as a significant number of those coal plants between 300 and 500 megawatts of capacity.

To put this in perspective, in Missouri, I have almost 600,000 households, 1.5 million people approximately that make less $25,000 per year. That is according to the U.S. Census statistical abstract. I depend on these old coal plants to generate electricity almost every day for more than 2 million households. Why? Because they are still cheaper to operate and cheaper to dispatch than natural gas plants. Replacing them with renewables creates more of a reliability problem, and replacing them with gas will undoubtedly lead us back to the gas affordability crisis that we faced two or three times in the last decade.

I submit to you that if you want the price of natural gas to go back up, all we have to do is have our utilities plan and build resources based on the premise that natural gas will be cheap and plentiful for the next 10, 20 or 30 years, and that is where we are headed.

From a transmission perspective, by forcing the closure of a coal plant or small clusters of coal plants, these regulations are going to create pockets on the grid that have an increased risk of reliability issues because the grid was designed and built on the premise that those plants are going to be there providing voltage support to satisfy local load requirements throughout the country. I haven't plotted out where these plants are on a map but I can assure you that the absence of these plants will change the flow of power on the grid and create reliability issues in some areas.

Turning to the actual effect of the EPA regulations on my State, these costs are going to be a significant burden. We all like clean air but the people I have need jobs. For example, the scrubbers used to remove particulates and gases cost anywhere between $250 million to $300 million per unit. We just spent $528.1 million to retrofit one coal plant to put scrubbers on. EPA has got more than a dozen regulations that are currently working their way through the pipeline. When you figure a 10 percent return on that investment, gross that number up for taxes and amortize the costs over 30 years, it is ultimately going to cost my ratepayers approximately $1 billion. If you assume that utility has 1.2 million customers and divide the costs out on a per-customer basis, you are looking at close to $1,000 per customer over the next 30 years. It is that cost to a residential consumer as well as the impact it will have on small business and industry that I am concerned about.

In Missouri this year already, we have an estimated 26 heat-related deaths this year. Eighteen are still pending a final determination. In some cases and in certainly past cases, there was evidence that those customers actually had functioning air conditioners, they just weren't using them because in all likelihood they were afraid they couldn't pay their bills.

In all honesty and in conclusion, I am just not sure how much more of this help my ratepayers can afford.

[The prepared statement of Mr. Davis follows:]

Commissioner Jeff Davis
Missouri Public Service Commission
Committee on Energy and Commerce
September 14, 2011
Subcommittee on Energy and Power

Chairman Whitfield and members of the committee:

Thank you for allowing me the opportunity to appear before this subcommittee. I have to preface my remarks by saying that I am here appearing on my own behalf and that my comments are solely my opinions and should not be attributed to any other group I may be affiliated with.

As a commissioner of the Missouri Public Service Commission and as President of the Regional State Committee for the Southwest Power Pool, I am acutely aware of the potential impacts of the pending regulations currently being promulgated by the Environmental Protection Agency. Further, I appreciate and applaud this committee's review of the impacts those regulations will have on our citizens, our states and our nation's economy.

Essentially, we've been invited here today to answer two questions regarding the EPA's new and proposed power sector regulations:

(1) Can we keep the lights on?

(2) How will these regulations impact utility ratepayers, commerce and industry?

The answer to the first question is simple: Yes, we'll do whatever it takes to keep the lights on.

That being said, it won't be easy and more people will be unable to pay the costs to keep their lights on without outside assistance. Nobody knew there was a problem in Arizona, Southern California and Baja under the current system until 1.5 million Americans were left in the dark less than a week ago and reliability is definitely going to be impacted.

The answer to the second question is more complex, but two points need to be made here:

(1) Less generation equals less reliability; and

(2) Replacing these coal-fired plants with a new type of generation will create a whole new set of problems and risks.

Right now, we've got better than 20% reserve margins in both the SPP and MISO footprint. The cumulative effect of these regulations will be to significantly reduce those reserve margins over the next decade by forcing the closure of almost every coal unit in the country that's below 300 MW of capacity as well as a significant number of units having between 300 – 500 MW of capacity. There have been more than a half dozen studies done on the issue and each one estimates the cumulative effect to be a loss of anywhere between 10 and 70 GW of coal-fired generation.

You also have to keep in mind that these are baseload plants – units that run more than 1,500 hours a year. Replacing them with renewables creates more of a reliability problem and replacing them with gas will undoubtedly lead us back to the affordability crisis we've faced two or three times in the last decade. As one creates greater demand for natural gas to be used to support the production of electricity, this increased demand will result in higher costs for natural gas to be used to heat our homes and businesses. This increased natural demand will increase the costs for domestic manufacturing processes. Such costs increases should not be incurred until other alternative approaches have been fully examined to explore options that could avoid these costs increases.

There are also risks from a transmission perspective. By forcing the closure of a coal plant or small cluster of coal plants, these regulations are going to create some pockets on the grid that have an increased risk of reliability issues because the grid was designed and built on the premise that those plants are going to be there providing voltage support to satisfy local load requirements in respective systems throughout the country. I haven't taken the time to start plotting out where these plants are on the map, but you can rest assured that the absence of those plants will change the flow of power on the grid and create reliability issues in some of those areas.

I want to leave you with one final story on this issue that's close to home for me. In late January 2009, a massive ice storm swept through the Central United States and the Southeast destroying miles of high voltage transmission lines that many of our utilities depend on to serve their customers. A number of municipal utilities like Malden, Missouri, and Piggott, Arkansas, were able to quickly restore power using their old backup diesel generators. There are hundreds of these units throughout the Midwest, a lot of them date back to the World War II era and in times of emergency like that ice storm or on peak days when the system's congested those generators have proven to be an invaluable resource. Now, one rule – the Hazardous Air Pollutant Rule for Compression Ignition Reciprocating Internal Combustion Engines (HAPS CI RICE) is forcing us to mothball all of those plants because they're cutting off the funds used to maintain and repair the units because they don't have SCR or the necessary run-time to qualify.

Turning to the actual effect of these EPA regulations themselves, I can tell you that if all of these regulations come to pass they are going to have a devastating effect on Missouri's economy and our people.

Missouri has approximately 50 coal plants, totaling almost 13,000 MW of capacity. More than 80% of the electricity actually consumed in Missouri comes from coal. I need those plants to serve our native load, so we're married to coal for the next half century or longer whether you like it or not.

More importantly, the stable supply of energy supplied by those plants combined with sharp-penciled regulation has produced some of the lowest electric rates in the country. Those rates and the reliability of those plants have attracted a number of manufacturers to Missouri over the years and now those jobs are being threatened by rising rates.

Fitch has estimated electric rates are going to rise 3-5% annually while wages are going to remain stagnate. Missouri will be especially hard hit because we burn a higher percentage of coal than most other states. Those costs will significantly increase the burden on residential, commercial and industrial customers alike for three reasons:

(1) You've got the cost of the physical equipment you have to install, the installation itself and the lost productivity from the plant during installation;

(2) From an operational standpoint, EPA doesn't give utilities enough collective time to design the necessary plant changes, build the necessary infrastructure and implement all the new required changes from an operational standpoint without incurring tens or even hundreds of millions of dollars of additional costs on a per unit basis; and

(3) The rules being promulgated by EPA are analyzed only on the basis of the effect that single rule will have and not their cumulative effect. When implementing those rules, utilities and manufacturers have to cope with more than a dozen major rules in the aggregate – including a few that conflict with one another.

For example, scrubbers used to remove particulates and gases cost anywhere between $250 - $300 million per unit. In the most recent major rate case to come before the Missouri commission, we determined that the prudently incurred costs associated with adding scrubbers to a single plant – ONE plant to meet ONE regulation on ONE pollutant – was $528.1 million.

When you figure a 10% return on investment equity, gross that number up for taxes and amortize the costs to ratepayers out over 30 years, it's ultimately going to cost the utility's ratepayers about $1 billion. If you assume the company has 1.2 million customers and divide those costs out on a per customer basis, you're looking at almost $1,000 per customer over the next 30 years. Adding these costs to small business in today's uncertain economy can have devastating impacts. Just the fear of these costs impacts business negatively as current decisions are being made regarding a future uncertain time period when costs of doing business can be significantly higher. This uncertainty threatens to make current business decisions inappropriate in the future depending on which cost scenario materializes.

To give you a little more perspective on that number, Missouri has almost 600,000 households – almost 1.5 million people – that don't make $25,000 a year as a household. They're having a hard enough time paying their bills already. They can't afford anything else.

In Missouri, there have already been an estimated 26 heat-related deaths this year. 18 deaths are still pending a final determination. In some cases, there was evidence that the customers actually had functioning air conditioners, they just weren't using them because in all likelihood they were afraid they couldn't pay the bills as they needed their money to pay for food and shelter. These EPA rules aren't going to be able to help customers who share that dilemma.

If time permits, I'd like to share two more examples:

First, another Missouri utility installed SCR at a plant that was originally estimated to cost $270 million. By the time it was installed, their final cost ballooned to more than $420 million due to the overtime they had to pay for a compressed work schedule and it being a seller's market in that they were out there competing with every other coal-burning utility in the United States for engineering and construction resources. You couldn't get fixed price contracts, liquidated damages clauses or many of the standard consumer protections because the engineering firms would just say "we'll go work for somebody else." I was told that in at least one case the work was even outsourced by the U.S. firm to a foreign company.

Second, EPA has issued two different sets of draft rules to regulate coal ash – known as Coal Combustion Residuals. One EPA rule would classify this as hazardous waste. Another classifies it as a special waste. This coal ash is currently used as a filler in concrete that builds everything from roads to buildings. If it is classified as a hazardous waste, as one rule holds, it could no longer be used for this purpose, thereby eliminating a $2 billion industry in the U.S. If it is classified as a special waste, more costly storage processes would be required.

While those two rules conflict, EPA has drafted another rule – the Electric Generating Unit Maximum Allowable Control Technology (EGU MACT or Mercury Rule) in which EPA selected dry sorbent injection technology for mercury. Yes, this method controls mercury emissions. However, using this technology renders the ash unusable for a concrete additive because it increases the sodium level beyond that allowed by the cement industry's standards for cement.

The cost of EPA regulations, in terms of direct costs to ratepayers, as well as the cost of attempting to comply with these rules under accelerated timelines, will exact a dear price paid by everyone in this country who uses electricity. Rates are going to rise, more people aren't going to be able to pay their bills, more jobs are going to move overseas and U.S. manufacturers are going to be further disadvantaged.

The timing of the implementation of any such EPA regulations should consider the time required to allow the US to develop the industry needed to support the construction, operation, and maintenance of related facilities here in America. Without consideration of this objective, a significant portion of these EPA regulation expenditures will go overseas and result in the loss of the opportunity to create these jobs here in the US.

Six days ago, the president of this nation stood before this Congress and said these words: "We should have no more regulation than the health, safety and security of the American people require. Every rule should meet that common sense test."

I commend the chairman and the subcommittee for holding this inquiry and I would encourage you to hold EPA accountable for their actions and to make sure their rules do, indeed, meet the "common sense test" to which the President referred. Again, I thank the committee and the chairman for the privilege of testifying before you today. I'm happy to answer any questions.

Mr. WHITFIELD. Thank you, Mr. Davis.

Mr. Wise, you are recognized for 5 minutes.

STATEMENT OF STAN WISE

Mr. WISE. Thank you, Mr. Chairman. Thank you, Ranking Member Rush. My name is Stan Wise. I am a publicly elected commissioner of the Georgia Public Service Commission, and I currently serve as its chairman.

As a utility regulator, I am responsible for ensuring that retail electricity customers in Georgia receive reasonably priced and reliable electric service, and like the rest of the United States economy, the economy of Georgia has suffered and our unemployment rates are above the national average. I worry that the cost and the reliability impacts of the new environmental rules will only further slow our recovery and cost jobs.

During most of the last 10 years, Georgia was growing and we added 1.5 million new residents. Electricity generation increased by 40 percent and job growth increased by 140,000. At the same time, Georgia has been active in addressing power plant emissions with significant reductions including mercury through the State rules with reasonable compliance schedules. The cost of these emission reductions are already borne by the citizens of the State of Georgia. Customers of Georgia Power see an environmental line item on their bills currently averaging over $7 a month for household customers.

My two principal concerns with this fleet of new regulations are this. First, I am concerned that there have been no comprehensive studies by the EPA to assess the impact of all of these rules on the price of electricity, on jobs, on the reliability of supply and the overall economy in our State. EPA only evaluates each rule in isolation, that is, the impact of one rule independent of all other regulatory actions. This is a very real issue for me because my Commission and Georgia utilities must consider the effect of all regulations in deciding how to comply cost-effectively while maintaining reliability. The EPA has not looked at these regulations in a comprehensive manner. Independent groups have examined the rules and they report double-digit increases in electricity rates over the next 10 years, job losses in the Southeast in the hundreds of thousands, and single-digit reserve margins. To me, the EPA's approach in analyzing the impact of these rules appears to be shortsighted and simplistic. It just doesn't make sense.

My second concern with these fleet of regulations is the impact on reliability. How do they affect reliability? First, our reserve margins mentioned above in several studies represents actual assets that are available to provide electricity if demand increases or a plant fails. Without sufficient reserve margin, there is a highly increased risk of outages and blackouts. The assessment of future reserve margin is a critical component of my Commission's examination of future power needs and decisions on generation. This is key. The rules don't provide sufficient time for an orderly, deliberate technology installation program as has been the case with past environmental rules, nor do they allow time for construction of replacement generation.

The emphasis on this point is, we just don't know how much technology is required or the potential requirements. We don't have sufficient time to install controls, do not have time to build new generation. This is what causes me and my colleagues great concern on reliability. It is not a responsible approach to managing our energy supply.

I have other issues discussed in my written testimony where utilities have been forced to guess at compliance strategies, and the EPA's failure to engage State agencies such as mine in the development of these new rules. I am concerned about both the power industry that I regulate and the Georgia customers that I am entrusted to protect. These environmental rules have large impacts and the EPA has not studied the cumulative impact of the rules aimed at air emissions, coal ash and water issues. This hearing is focused on reliability, and I am concerned that for my State where we have already proposed the retirement of 569 megawatts of coal capacity and deferring action on another 2,600 megawatts of coal capacity until these regulations are final. The impossibly short time frame for compliance is also a concern that affects electricity reliability, not to mention the downrange jobs and community impacts associated with power plant retirement.

Congress could aid in making this situation manageable by insisting upon a comprehensive study, preferably by an agency other than the EPA, on the impacts of these rules and by providing more realistic time frames for compliance that would both increase reliability and reduce cost. Thank you, Mr. Chairman.

[The prepared statement of Mr. Wise follows:]

Testimony of Stan Wise,
Chairman of the Georgia Public Service Commission

before the

U.S. House Energy and Commerce Committee
Subcommittee on Energy and Power

Hearing on Impacts of the Environmental Protection Agency's New and Proposed Power Sector Regulations on Electric Reliability

September 14, 2011

Good Morning Mr. Chairman, Ranking Member Waxman, and Members of the Committee.

I am honored to be able to appear before this distinguished Committee today and present my testimony on this important subject.

My name is Stan Wise. I am a publicly elected Commissioner of the Georgia Public Service Commission, and I currently serve as the Chairman of the Georgia Commission. In the past, I was honored to have served as President of the National Association of Regulatory Utility Commissioners (NARUC). As a utility regulator, I am responsible for ensuring that retail electricity customers in Georgia receive safe, reasonably priced, and reliable electric service. The State of Georgia has a deliberate, focused effort for resource planning for the electric sector. This process typically starts with the utility identifying needs for more generation, which my Commission certifies if the utility demonstrates it sufficiently. The utility returns to the Commission with a proposal to fill that need, and the Commission judges the prudency of their proposal. This is a robust effort and has served my state well.

The southeastern United States, and particularly my home state of Georgia, has benefited from a vibrant, growing economy that depends on reliable and affordable electricity. Recently though, the economy of Georgia has suffered with unemployment rates above the national average. I worry that the costs and reliability of new environmental rules will only further slow our recovery and cost jobs. The Georgia Chamber of Commerce in a recent letter to the Committee on Energy and Commerce (attached), expresses "our concerns with the anticipated negative economic consequences associated with the agency's [EPA] proposals."

Georgia has also been particularly active in addressing environmental concerns, with utility emissions steadily declining, while the economy grew, along with more energy sales. Since 2000 utility and industrial sources of sulfur dioxide emissions in Georgia have decreased by 58% and nitrogen oxides by 67%. (EPA Clean Air Markets, Data and Maps, State Level Emissions Quick Report at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard). During this same time period, Georgia added 1.5 million new residents (18.3% growth) and job growth increased slightly by 140,000 – in spite of the current recession (from household survey data). Electricity generation in the state increased by 40%. Going forward, a state environmental rule mandates the installation of emissions control technologies on all of the medium and large-sized coal-fired power plants in Georgia by 2016. Due to this state rule, mercury emissions have decreased by an estimated 67% from 2000. Therefore utility emissions from Georgia power plants have significantly dropped and will continue to decline. The costs of these emission reductions are already being borne by the citizens of Georgia. The major utility in Georgia, Georgia Power, has invested over $3.7 billion in capital for environmental projects through 2010. (See attached Georgia Power statement at EPA MACT Public Hearing, Atlanta, GA, 5/26/2011.) Theses added controls have already increased costs in Georgia. Customers of Georgia Power see a line item on their bills for the environmental portion of their electricity costs, which is a little over $7 per month for the average customer.

I am concerned that the current set of EPA rules facing the electric utility industry will cause reliability issues for the State of Georgia in addition to the whole United States. Currently, there are at least seven major regulatory actions that have been or are being developed by EPA that will affect the operation and viability of electric steam generating units in Georgia. They are:

- The Utility Maximum Achievable Control Technology (MACT) Rule
- The Cross-State Air Pollution Rule (CSAPR)
- The Coal Combustion Residuals Rule, also known as the Coal Combustion Byproducts Rule
- Steam Effluent Guidelines for water discharges from ash ponds and scrubbers
- National Ambient Air Quality Standards (NAAQS) for ozone, sulfur oxides, nitrogen dioxide, and particulate matter
- Cooling Water Intake Structure regulations, also known as the 316(b) Rule
- Regulation of Greenhouse Gases (GHG) from power plants

In my tenure – over 15 years – of regulating the electric utility industry, I have never seen the number, the breadth, or the potential impact that this whole group of regulations will have on the industry and on my constituents, the people of Georgia. Although I am very concerned about the costs of these regulations and the resulting increased electricity prices on the citizens and businesses of my state, today I would like to talk about the reliability of electric service. It is obvious in modern life that our manufacturing plants, transportation systems, banking and financial services, our hospitals and first-responders, and general commerce depend heavily on reliable and dependable electricity. Earlier this year, Georgia suffered a series of storms and tornados that produced widespread power outages, reminding us again how important electric service is to modern life, just like this region experienced with Hurricane Irene. I am proud that line crews from my home state were able to help get the power restored here in the District and in Virginia and Maryland. I think we can all agree that reliable, affordable electric service is a necessity of modern life.

I have two concerns about the reliability impacts of the environmental regulations facing the electric utility industry regarding reliability: (1) No comprehensive study has been done by EPA to assess the combined impact of all of these rules on the price of electricity, on jobs, on the reliability of the electricity supply, and on the overall economy; and (2) these rules as proposed and finalized don't provide sufficient time for an orderly, deliberate technology installation program, as has been the case with past environmental rules. So we don't know how much technology investment is required or the potential power plant retirements that could be caused by these rules – and causes me great concern from a reliability standpoint. This does not seem like a responsible approach to managing our nation's energy supply.

On the first point, my concern is that I do not have enough information to make regulatory decisions for the utility industry and consumers in my state. As far as I know, the Environmental Protection Agency has not conducted a detailed study of the entire set of rules that would estimate their impact on electricity prices, economic activity, number of jobs created or destroyed, and the reliability of electric service. I only am aware of EPA evaluations of each of these rules in isolation – that is, the impact of the rule assessed independent of any other regulatory activity occurring either at the same time or close in time. One of my concerns is this piecemeal evaluation approach can easily miss the big picture, because my Commission and the utilities must consider the effect of all the regulations in deciding how to comply cost-effectively while minimizing reliability impacts. The utility must make decisions about whether to control emissions from a plant, or retire the plant and find alternate ways to supply electricity to their customers. To me, EPA's approach to analyzing the impact of these rules appears to be short-sighted and simplistic. It just does not make sense.

Apparently EPA has or intends to involve others in assessing these impacts. In the proposed Utility MACT rule published in the Federal Register on May 3rd of this year, EPA wrote (on page 25054, emphasis added):

> In addition, EPA itself has already begun reaching out to key stakeholders including not only sources with direct compliance obligations, but also groups with responsibility to assure an affordable and reliable supply of electricity **including state Public Utility Commissions (PUC)**, Regional Transmission Organizations (RTOs), the National Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and DOE. EPA intends to continue these efforts during both the development and implementation of this proposed rule.

I am not aware of any interaction between the Georgia Public Service Commission and EPA on these issues. We were not contacted during the development of the MACT proposal, and have not been contacted since then while EPA is developing the final MACT rule – which is promised to be signed on or before November 16, 2011.

On the other hand, there are studies that have been published that attempt to address the cumulative impact of these rules on the utility sector and the broader economy. National Economic Research Associates, Inc. has published a study which analyzes the impact of just two of these rules, the Cross-State Air Pollution Rule and the Utility MACT rule. (See http://www.americaspower.org/NERA_CATR_MACT_29.pdf). The conclusions of their work were that:

- Average U.S. retail electricity prices in 2016 would increase by about 12%, with regional increases as much as about 24%

- Net employment in the U.S. would be reduced by more than 1.4 million job-years over the 2013-2020 period, with sector losses outnumbering sector gains by more than 4 to 1.

Additionally, NERA estimates that coal plant retirements nationally would increase by 48 GW for these two rules. (In contrast, EPA estimates only 10 GW of coal retirements for the Utility MACT rule.)

Similarly, Southern Company, the parent company of Georgia Power, state in their comments on the MACT rule (see attached Southern Company press release, dated August 4, 2011):

> The capital spending and fuel switching required for compliance with EPA's proposed rules could increase electricity prices an additional 10 percent to 20 percent over the next 10 years for customers of Southern Company's subsidiaries. Southern Company's analysis of other studies by NERA Economic Consulting, Management Information Services and others indicates that electricity prices in the Southeast could increase 10 percent to 25 percent over the same 10-year period with job losses between 250,000 to 500,000.

In their MACT comments (http://www.southerncompany.com/news/news_utility_mact.aspx), Southern Company quotes a Bernstein Research study (Bernstein Research, Black Days Ahead for Coal: Implications of EPA Air Emissions Regulations for the Energy & Power Markets Mar. 19, 2010) which found that:

> "regional capacity margins would be reduced by 7 to 15 percentage points, to 4% in SERC [SERC Reliability Corporation, which includes Georgia] …"

These comments go on to say:

Consistent with this research, based on EPA's rules, Georgia Power projects an extremely low reserve margin in 2015.

These studies are the basis for my strong concern over reliability. Reserve margin represents actual assets that are available and able to provide electricity if demand increases or there is an equipment problem with operating generation. Without sufficient reserve margin, there is increased risk of outages and blackouts.

For Georgia, the major utility in the state, Georgia Power, has said in a 10-Q quarterly filing (see http://investor.southerncompany.com/secfiling.cfm?filingID=92122-11-103&CIK=041091, emphasis added):

> Georgia Power has completed a preliminary assessment of the EPA's proposed Utility Maximum Achievable Control Technology (MACT), water quality, and coal combustion byproduct rules. [..] Although its analysis is preliminary, Georgia Power estimates that

> the aggregate capital costs for compliance with these rules could range from $5 billion to $7 billion through 2020 if adopted as proposed. [...] Georgia Power's preliminary analysis further indicates that **the short timeframe for compliance with these rules could significantly impact electric system reliability** and cause an increase in costs of materials and services.

Therefore, the planning of the largest utility in my state estimates electricity price increases of 10-25%, the regional loss of jobs of between 250,000 and 500,000, and the significant potential for reliability impacts. I believe that before we rush into these rules Congress should require EPA – or preferable some other body – to assess the impacts of the entire set of rules on reliability, and also look at jobs, prices, and the economy.

My second concern with this set of rules – and with the Utility MACT in particular – is the unreasonably short time allowed for compliance, which requires planning, regulatory approvals, permits, and construction to address the rules. I am saying that sufficient time for a deliberate, orderly, and cost-effective compliance response is necessary. In fact, one utility in my state, Georgia Power, has set the industry standard for timely deployment of control technologies. Compression of the installation schedule expected by these rule is patently unrealistic, with higher energy prices and compromised energy reliability the likely consequence. Short timeframes for compliance effectively limit control options. They also create a risk that some affected sources will be unable to comply and thus unable to operate for some period of time until they can comply.

This is not a hypothetical issue for us. The Georgia Commission has recently received an Updated Integrated Resource Plan from Georgia Power that was prompted specifically to address the anticipated impacts of all of these new and future environmental requirements. (See attached public version of the Georgia Power IRP Executive Summary). In this updated plan, Georgia Power estimates that as many as 2,000 MW will be unavailable in 2015, because they cannot be controlled in time to comply with these regulations. Even if they could, the combination of proposed and anticipated regulations make decision-making on controls difficult if not impossible in the absence of final rule. In this filing, Georgia Power has asked my Commission to approve the retirement of two coal plants, enter into purchased power agreements for over 1,500 megawatts in 2015 to ensure reliability, and to start working on baghouse filters for their large coal power plants in anticipation of the Utility MACT rules. It is rare for a utility to ask the Georgia Commission to start expending resources ahead of a final rule – and that action is directly due to the impossibly short time frame for Utility MACT compliance.

Additionally this filing also lays out a demand side approach by the utility, where the company projects that Demand Side Management (DSM) and Energy Efficiency (EE) will reduce capacity requirements by approximately 2,600 MW over the next ten years.

With regard to the short compliance time for the MACT rule, EPA offers two solutions. The first is that the Clean Air Act allows a one year compliance extension for installation of technology, thus providing a possible four years for compliance. The one-year is not automatically granted, and thus there is uncertainty about whether this extension will be widely available. Utilities do not know if they will be granted the one-year extension, contributing to the uncertainty in their planning.

The second solution offered by EPA is that utilities should start acting now based on the proposed rule to achieve compliance with the final MACT rule by the required date. In the proposed rule (Federal Register, May 3, 2011, page 25056), EPA says (emphasis added):

> to achieve compliance in a timely fashion, EPA expects that sources will begin promptly, **based upon this proposed rule**, to evaluate, select, and plan to implement, source-specific compliance options.

While this may make some sense, and this is exactly what Georgia Power is requesting, the problem that I see is that EPA has a history of making significant changes between proposed and final rules. Two very recent examples illustrate the issue well. In the first, the Industrial Boiler MACT was proposed by EPA on June 4, 2010. The Agency then published a final rule – under a court-ordered deadline – on March 21, 2011. On May 16, 2011, EPA delayed the effective dates of these rules until sometime into the future. Obviously, if a source had started a capital project based on the proposed Industrial Boiler MACT Rule, it may have started too early – given the uncertain final compliance date. They could also have been designing and constructing a control technology that could have been either over-designed or not adequate to meet the final standards. The "final" standards are still not yet final. EPA is reconsidering the rule because (http://www.epa.gov/airquality/combustion/docs/20110516nextstepfs.pdf):

> [...] the public did not have sufficient opportunity to comment on these changes, and, as a result, further public review and feedback is required to meet the legal obligations under the Clean Air Act.

A second example is the recently finalized Cross-State Air Pollution Rule (CSAPR). The proposed rule, published August 2, 2010, was followed by 3 additional requests for more information, resulting in a final rule published on August 8, 2011. From the proposed rule to the final rule, there were very significant changes. For Georgia, the state lost substantial emissions allowances (thus making it harder for the state to comply) and was also placed into a different group of states for trading sulfur dioxide emissions. The state of Texas was not included in the proposed rule, but was inserted into the final rule. Thus with the CSAPR, similar to the Industrial Boiler MACT, any actions taken by the utilities in Georgia based on the proposed rule would have likely been inadequate due to the significantly stricter provisions in the final rule versus the proposed rule. To me, EPA's reliance on sources acting early on a proposed rule is misguided, given the history of wide changes from proposed rules to final rules. As a regulator, I hold utilities to a standard of fiscal prudency. The Commission's expectation for a utility to be able to recover their investments from their customers is they must be judged to have made prudent decisions on contemporaneously known information. The shifting sands of these rules make prudent early action impossible.

One approach used by EPA to justify short compliance times for the CSAPR and the Utility MACT is the choice of a particular technology for controlling acid gases, including sulfur dioxide. EPA assumes that 56 GW of coal-fired power plants will install dry sorbent injection (DSI) to meet part of the MACT standard. However, there is not a single power plant in EPA's database that met the MACT acid gas standards with this technology. DSI is a new and unproven technology that – in some cases – can reduce acid gases and sulfur dioxide. This approach by EPA is something that the Agency has done previously. That is, they have chosen to model a simple, untested technology and then use it to justify low capital costs and quick compliance timelines. In previous rules, EPA has pushed low NOx burners for nitrogen oxides, selective non-catalytic reduction systems for nitrogen oxides, activated carbon injection into existing electrostatic precipitators for mercury control, and now DSI for acid gas control. Each of these choices of technology by EPA has a common feature – their models overestimate performance and underestimate cost. History has proven that these simple technologies are not the right choice: selective catalytic reduction systems are the technology of choice for nitrogen oxide control and activated carbon injection into baghouse filters for mercury control. It is likely that DSI will only be used in a small number of power plants, and both the actual costs and time required for compliance will be much greater than EPA's models suggest using this flawed technology choice.

I would like to make one final comment on the Utility MACT in particular. I understand that the new coal plant requirements in the MACT proposal are so stringent that no new coal plants will be built. It is a mistake to base our national energy policy on this one rule, and place self-imposed limits on our economy by failing to use wisely our most abundant and secure fuel. New coal plants must be very low in emissions, but need a practical emission standard that does not preclude their construction. I urge the Subcommittee to investigate this part of the MACT rule. The long-term sustainability of my state's – and the nation's – economy will be much more difficult if we limit such a valuable fuel, only to see it shipped overseas for fuel in other countries.

In summary, I am concerned about both the power industry that I regulate and the Georgia customers that I am entrusted to protect. These environmental rules have large impacts, and EPA has not studied the total impact of the rules affecting air emissions, coal ash, and water issues. This hearing is about reliability, and I am concerned about that for my state. Georgia Power has already proposed the retirement of 569 MW of coal capacity, and is deferring a decision on an additional 2,600 MW of coal capacity until the final form of all of these regulations is clearer. The impossibly short timeframes for compliance is also a concern that affects electricity reliability. The three years (plus the possibility of one year additional) for the Utility MACT and the five months from final rule to compliance for the CSAPR will surely have an impact on electricity supply and ultimately on reliability – not to mention the down-range jobs and community impacts associated with these power plant retirements.

Congress could aid in making this situation manageable by insisting upon a comprehensive study – preferably by an agency other than EPA – on the impacts of these rules and by providing more realistic timeframes for compliance that would increase reliability and reduce costs.

Attachments:

- A. Georgia Chamber Letter re EPA.pdf
- B. Georgia Power Utility MACT hearing statement.pdf
- C. Southern Company MACT Press Release.pdf
- D. Pages from 2015 Application 8_1_11 PUBLIC DISCLOSURE_FINAL.pdf

GEORGIACHAMBER

September 9, 2011

The Honorable Fred Upton
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Henry Waxman
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Upton and Ranking Member Waxman:

The Georgia Chamber of Commerce, on behalf of our nearly 3,000 members representing over one million employees across the state, would like to express our support for H.R. 2250/S.1392, the *EPA Regulatory Relief Act of 2011*, H.R. 1705 *Transparency in Regulatory Analysis of Impacts on the Nation (TRAIN) Act of 2011* and H.R. 2273 the *Coal Residuals Reuse and Management Act*. These proposed regulatory relief initiatives are paramount to improving the economic outlook for Georgia and the rest of the nation.

The Chamber has maintained a strong interest in several rules proposed recently by the Environmental Protection Agency (EPA). We submitted formal comments and testified at a public meeting in recent months in an attempt to share our concerns with the anticipated negative economic consequences associated with the agency's proposals. Consistent with our position, we commend the President's recent acknowledgements of the need for "reducing regulatory burdens and regulatory uncertainty" in his move to delay the agency's new ozone standard. At this time of economic difficulty for businesses and families, government should be looking for ways to energize economic activity rather than squelch it though increased regulations. The enormous anticipated economic costs and job reductions associated with EPA's proposed rules accompanied by limited and questionable societal benefits make it imperative that Congress exercise its oversight responsibilities in these matters. These bills would help provide much needed analysis and input into the EPA's rulemaking process.

President Obama's recognition of the potential economic damage of EPA's rules is directionally accurate. His recent action is an important first step in reducing the heavy-handed regulatory burdens proposed by EPA. If enacted, H.R. 2250, H.R. 1705 and H.R. 2273 will offer additional much-needed relief for businesses and industries of all sizes. The late Georgia Senator, Paul Coverdell, frequently made the point that capital does not flow toward uncertainty. Businesses in Georgia and across the nation need regulatory certainty for planning purposes and the current suite of federal rules prevent that. We encourage your support of these bills to offer businesses greater confidence for investing capital to lift the collective economic future of this nation.

We appreciate your attention to this important issue and your willingness to consider much-needed regulatory relief during these challenging economic times.

Sincerely,

C Clark

Chris Clark
President and CEO

Doug Carter | Chris Clark
2011 Chair | President & CEO

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GEORGIA CHAMBER

cc: The Honorable Saxby Chambliss
The Honorable Johnny Isakson

The Honorable Jack Kingston
The Honorable Sanford Bishop
The Honorable Lynn Westmoreland
The Honorable Hank Johnson
The Honorable John Lewis
The Honorable Tom Price
The Honorable Rob Woodall
The Honorable Austin Scott
The Honorable Tom Graves
The Honorable Paul Broun
The Honorable Phil Gingrey
The Honorable John Barrow
The Honorable David Scott

U.S. EPA Public Hearing
Atlanta, Georgia

National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

Ron Shipman
Vice President Environmental Affairs
Georgia Power Company

Oral Statement
May 26, 2011

Thank you for holding this hearing today. My name is Ron Shipman, and I am the Vice President for Environmental Affairs at Georgia Power Company. Georgia Power is the largest operating company of the Southern Company, and is the largest electricity supplier in Georgia with over 2.3 million customers. We are committed to providing reliable and affordable electricity to our customers, while protecting and preserving the environment. Through 2010, Georgia Power has invested over $3.7 billion dollars in environmental controls and estimates we may need to spend another $2.6 billion to comply with existing environmental rules over the next three years.

The proposed Utility MACT rule will have a significant impact on our customers and the economy of Georgia. We own or operate up to 35 boilers affected by this rule. Those units supply 2/3 of all of the electricity produced by Georgia Power for its customers. We are concerned about many aspects of the proposed rule, but today I would like to focus on why the three-year MACT compliance timeline is unreasonable and could put the reliability and affordability of Georgia's electric generating system at risk. Based on our experience, this timeline is unworkable given the stringency of the proposed rule.

Georgia Power has installed scrubbers at 11 units, selective catalytic reduction systems at 8 coal-fired generating units, and fabric filter baghouses at 4 units. Under our current planned construction program, by 2016, we will have 19 units with scrubbers and 15 units with SCRs. When it comes to installing emissions controls, we have a wealth of experience.

Our experience tells us that the installation of multiple controls at multiple facilities cannot occur in three years. Even if we are able to obtain a one year extension for some units, there is not enough time to design and construct all of the controls. Furthermore, our experience tells us, the more compressed the time schedule, the higher the impact on the feasibility and cost of the projects and greater the impact on electricity rates.

Our technology experts believe that the proposed rule would require virtually every coal plant to operate scrubbers and most likely baghouses to meet the proposed emissions limits. Georgia Power is currently analyzing planning cases that involve construction of 8 to 12 additional baghouses on our largest units, in addition to the scrubbers that are already planned over the next 3 to 4 years. And this aggressive plan does not cover our entire fleet. Yet, we have concluded that even controlling this subset of our fleet cannot be done in 3 years, regardless of cost. Even if we are able to obtain a one year extension and looking at only this subset of our fleet, compressing the work into a 4 year schedule will escalate the required cost significantly and unnecessarily, which will directly impact our customers.

Plant Scherer near Macon, Georgia is a good example of what it can take to install multiple controls at a single facility. This plant is the largest coal-fired electricity producer in the United States. We are in the midst of an ambitious environmental retrofit program that will equip each of the 4 units with SCRs, scrubbers, and baghouses, in addition to the existing electrostatic precipitators. Upon completion, this site will be one of the best controlled coal power plants in the country.

The baghouses alone for the four Scherer units took approximately 5 years from start to finish, including design, installation, and startup. The cost was $558M. Retrofitting an existing facility that was not designed for the equipment presents unique challenges that put pressures on cost and schedule. As a simple example, at Plant Scherer, the Unit 3 baghouse had to be constructed nearly 1,200 feet from the electrostatic precipitator because there simply was not enough space to install the equipment any closer. To span that distance, the ductwork alone costs about $22,000 per foot, totaling tens of millions of dollars. With the addition of scrubbers and SCRs, the design, engineering, and construction program for all of the retrofit environmental controls at Scherer will take about 9 years. We are not taking our time building these controls. This is a very aggressive schedule that involves nearly 2,000 workers, 60,000 tons of steel, and hits nearly every usable space onsite. Throughout all of this construction work, the plant also has to operate. Our experience tells us that to complete multiple control installations requires careful planning and execution and, importantly, time.

Finally, our experience tells us that requiring an entire industry to install controls within a compressed time frame will result in material and labor shortages and dramatically escalating costs that EPA has not accounted for in its proposed rule.

Georgia Power is committed to providing reliable and affordable electricity to our customers, while protecting and preserving the environment. We simply ask for reasonable requirements and the time to meet the requirements at a pace that does not cause undue harm to our customers or put the reliability of Georgia's electric system at risk.

Thank you.

Southern Company Files Comments on Proposed EPA Rule

Aug 4, 2011

ATLANTA, Aug. 4, 2011 /PRNewswire/ -- Southern Company (NYSE: SO) today announced that it has completed a preliminary assessment of proposed federal regulations for coal-fired power plants and determined that the proposed rules would significantly impact customers and the overall U.S. economy as a result of higher costs for electricity and reduced reliability.

Southern Company's evaluation of how the various federal regulations would impact the company is included in formal comments being filed today with the U.S. Environmental Protection Agency (EPA) on the proposed Utility MACT (Maximum Achievable Control Technology) rule, which targets air emissions.

Southern Company Utility MACT Comments

Based on its current assessment of EPA's proposed rules, Southern Company's operating subsidiaries would expect to:

- install new emissions reduction equipment on approximately 12,000 megawatts (MW) of coal-fired generation, accounting for approximately 60 percent of the coal fleet,
- retire approximately 4,000 MW of coal-fired generation,
- change fuel for 3,200 MW or more of coal- and oil-fired generation to other fuels such as natural gas and
- replace more than 1,500 MW of coal- and oil-fired generation with natural gas-fired generation.

These actions would result in approximately 40 percent of the coal fleet being either retired or transitioned to natural gas.

Southern Company's analysis indicates that through 2020, the estimated capital cost for the company's operating subsidiaries to comply with the full range of proposed rules for coal-fired generation -- including air emissions, water and coal ash -- would be between $13 billion and $18 billion.

The capital spending and fuel switching required for compliance with EPA's proposed rules could increase electricity prices an additional 10 percent to 20 percent over the next 10 years for customers of Southern Company's subsidiaries. Similarly, Southern Company's analysis of other studies by NERA Economic Consulting, Management Information Services and others indicates that electricity prices in the Southeast could increase 10 percent to 25 percent over the same 10-year period with job losses between 250,000 to 500,000.

"EPA has an important and valuable role in America," said Thomas A. Fanning, Southern Company chairman, president and CEO. "In the past, our industry has had a constructive relationship with the agency. However, these proposals are misguided in their content and timing.

"We all want to maintain a clean environment, and we also want a healthy economy, which relies on reliable electricity at costs that people and businesses can afford," Fanning added. "The proposed Utility MACT rule along with the other proposed EPA rules will threaten reliability and drive up costs. We must work toward a more sensible solution."

Fanning stressed that "customers and communities in the Southeast have been struggling with the economic recession and unacceptably high unemployment rates. This unprecedented and ill-timed transformation of the nation's electricity infrastructure will only impede the U.S. economic recovery, reduce our ability to create jobs and add to the economic burdens of our customers."

Fanning said the company is "providing EPA with the information they need to fully understand the reliability risks, economic impact and significant social consequences the proposed rules will have."

For example, Fanning said the three-year compliance timeframe of the proposed Utility MACT is much too short. Based on Southern Company's experience, the installation of technologies for reducing sulfur dioxide emissions have ranged between 40 and 69 months, and projects to replace generation have averaged four to six years.

Refueling coal-fired generation to natural gas may also take four or more years, since at most locations interstate natural gas pipelines will need to be expanded. Significant changes in generation also will require substantial transmission upgrades requiring long-lead time transmission projects to maintain reliability. "The extremely compressed construction and outage schedules will needlessly drive up costs and threaten reliability," said Fanning. "The consequences of EPA's unreasonable timetable are significant to our customers and our nation."

Decreased property tax revenues and job losses also would have negative consequences for state and local governments. Specifically, counties where coal-fired generation is retired will experience severe reductions in tax revenues and property tax receipts.

"While some may argue that jobs lost at coal-fired generating plants will be replaced by jobs at natural-gas fired plants or by jobs installing the retrofits, the reality is that there will be a substantial net loss of jobs, payroll and taxes," said Fanning.

As a potential solution, Fanning said an extension of the Utility MACT compliance timeframe to at least six years, for example, would achieve the same environmental results, ease inflationary pressures, protect reliability and reduce the loss of jobs.

As rules become final, Fanning said Southern Company's operating subsidiaries will work with their state public service commissions and their environmental regulatory agencies to assure compliance.

Since 1990, the Southern Company system has already invested more than $8 billion in emissions reduction equipment. The system's emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) have been reduced by 70 percent while energy consumption has risen 40 percent.

With 4.4 million customers and more than 42,000 megawatts of generating capacity, Atlanta-based Southern Company (NYSE: SO) is the premier energy company serving the Southeast. A leading U.S. producer of electricity, Southern Company is the parent firm of electric utilities in four states and a growing competitive generation company, as well as fiber optics and wireless communications companies. Southern Company brands are known for excellent customer service, high reliability and retail electric prices that are below the national average. Southern Company was named the World's Most Admired Electric and Gas Utility by Fortune magazine in 2011, and is consistently listed among the top U.S. electric service providers in customer satisfaction by the American Customer Satisfaction Index. Visit our website at www.southerncompany.com.

Cautionary Note Regarding Forward-Looking Statements

Certain information contained in this release is forward-looking information based on current expectations and plans that involve risks and uncertainties. Forward-looking information includes, among other things, statements concerning economic recovery, economic growth environmental regulations and estimated expenditures, environmental compliance plans, estimated construction and other expenditures, plans and estimated costs for new generation, timing and completion of construction and other projects and sources of fuel. Southern Company cautions that there are certain factors that can cause actual results to differ materially from the forward-looking information that has been provided. The reader is cautioned not to put undue reliance on this forward-looking information, which is not a guarantee of future performance and is subject to a number of uncertainties and other factors, many of which are outside the control of Southern Company; accordingly, there can be no assurance that such suggested results will be realized. The following factors, in addition to those discussed in Southern Company's Annual Report on Form 10-K for the year ended December 31, 2010, and subsequent securities filings, could cause actual results to differ materially from management expectations as suggested by such forward looking information: the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations; current and future litigation, regulatory investigations, proceedings, or inquiries; variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures; available sources and costs of fuels; effects of inflation; ability to control costs and cost overruns during the development and construction of facilities; advances in technology; state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms; regulatory approvals and actions related to the construction projects; the direct or indirect effect on Southern Company's business resulting from terrorist incidents and the threat of terrorist incidents; the ability to obtain new short- and long-term contracts with wholesale customers, interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings; the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including the impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance and the economy in general; the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices; catastrophic events such as fires earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences; and the direct or indirect effects on Southern Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources. Southern Company expressly disclaims any obligation to update any forward-looking information.

SOURCE Southern Company

For further information: Southern Company Media Relations, +1-404-506-5333 or 1-866-506-5333, www.southerncompany.com

PUBLIC DISCLOSURE

Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants, and Updated Integrated Resource Plan

Docket No. 34218

August 4, 2011

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY'S APPLICATION FOR DECERTIFICATION OF PLANT BRANCH UNITS 1 & 2 AND PLANT MITCHELL UNIT 4C, APPLICATION FOR CERTIFICATION OF THE POWER PURCHASE AGREEMENTS WITH BE ALABAMA LLC FROM THE TENASKA LINDSAY HILL GENERATING STATION AND WITH SOUTHERN POWER COMPANY FROM THE HARRIS, WEST GEORGIA AND DAHLBERG ELECTRIC GENERATING PLANTS AND UPDATED INTEGRATED RESOURCE PLAN

DOCKET NO. 34218

Applicant name, address and principle place of business:

Georgia Power Company
241 Ralph McGill Blvd NE
Atlanta, Georgia 30308

Authorized person to receive notices or communications with respect to application:

Cofield Widner, Sr. Regulatory Affairs Representative
Regulatory Affairs, BIN 10230
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Location for public inspection:

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241 Ralph McGill Blvd NE
Atlanta, Georgia 30308

1. Executive Summary

Georgia Power Company ("Georgia Power" or the "Company") makes this filing ("Application") as part of its continuing efforts to provide a cost effective and reliable supply of electricity for its customers at a time of significant uncertainty for the electric utility industry. Georgia Power, along with the entire industry, is faced with an unprecedented confluence of new environmental regulations promulgated by the United States Environmental Protection Agency ("EPA" or "Agency"). The new and anticipated regulations are far reaching and effect a wide-range of areas including numerous air, water and waste matters. These regulations, some of which impose unrealistic timeframes for compliance, place significant uncertainty on the reliability of the electric system and will impose significant compliance costs on our customers. Because many of the regulations are still at the proposed rule stage or have yet to be proposed, the ultimate impact remains uncertain. What is certain, however, is that the Company must take steps now to prepare to deal with the challenges that these new regulations are expected to place on reliability in 2015.

The Company has undertaken a thorough analysis to determine the most cost-effective approach for providing the reliable service that its customers have come to expect. In doing so, the Company faces the challenge of developing strategies to comply not only with current environmental regulations, but also with proposed and anticipated regulations, taking into account the significant uncertainty created by those future regulations. One regulation of particular importance to this Application is the EPA's proposed regulation to set national emission standards for hazardous air pollutants from coal- and oil-fired electric utility steam generating units ("Utility MACT"). The Utility MACT rule as currently proposed would require additional emissions control equipment on the majority of the Company's generating units. The Utility MACT rule would also have one of the earliest compliance deadlines, with compliance required as early as 2015 with the possibility of a one-year extension under EPA's current schedule. The EPA is required to release a final rule by November 16, 2011. The impact that this rule will have upon reliability in 2015 and beyond is a major driver for the actions requested in the Company's Application as described in greater detail herein.

PUBLIC DISCLOSURE

Based on its extensive analyses of these rules and the anticipated impacts, the Company has put forth in this Application a cost effective approach that provides for the decertification of certain coal- and oil-fired units. The Company also proposes to begin work on environmental controls necessary to provide for the continued operation of certain coal fired units that are cost effective to control based upon anticipated environmental regulations. As a result of the uncertainty surrounding pending environment regulations, the Company plans to defer the decision to control or fuel switch approximately 2,600 megawatts ("MW") of capacity until the Company has greater certainty regarding the final form of the pending regulations, including the Utility MACT rule. By deferring these decisions, the Company will be able to make more informed decisions at a later date to control or decertify these units in a cost effective manner for customers. The short compliance timeline under the proposed Utility MACT rule and the need for greater certainty around the pending environmental regulations is expected to render at least 2,000 MWs of capacity unavailable in 2015. To address the deficit created by the unavailability of these units and to strive to maintain reliability in 2015, the Company is proposing to certify 1,562 MW of purchase power agreements.

Specifically, Georgia Power requests that the Georgia Public Service Commission (the "Commission") do the following:

(1) Decertify Plant Branch Unit 1 and Plant Branch Unit 2 effective with the revised Georgia Multipollutant Rule compliance dates for these units, and decertify Plant Mitchell Unit 4C effective as of the date of the final order in this proceeding;

(2) Approve the reclassification of the remaining net book values of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;

(3) Approve the amortization of approximately **REDACTED** of Plant Branch Units 1 & 2 environmental construction work in progress ("CWIP") (which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;

(4) Approve the amortization of any remaining, unusable material and supplies ("M&S") inventory balance remaining at the unit retirement dates which will be reclassified to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 ratably over a three year period beginning January 2014;

(5) Approve the Company's decision to initiate the work necessary for the possible installation of baghouses on certain coal-fired generating units, which it expects will be necessary to help the Company strive to meet the anticipated compliance deadlines for the Utility MACT rule and approve the Company's proposed treatment for recovery of the related costs;

(6) Grant a certificate of public convenience and necessity for the four power purchase agreements ("PPAs") selected through the 2015 Request for Proposals ("RFP") and approve the Company's proposed treatment for recovery of the related costs; and

(7) Approve the 2011 Integrated Resource Plan Update ("2011 IRP Update").

The actions described in this Application are part of the Company's near term plan to help assure reliable service in an uncertain environment. In developing this plan, the Company has taken into account, to the best of its ability, the known and potential costs of complying with both existing and anticipated environmental regulations, as well as the logistical and scheduling challenges presented by the various regulations.

The Company first requests that the Commission decertify Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C. Under the Georgia Multipollutant Rule, Plant Branch Units 1 & 2, which total approximately 569 MW of capacity, will be required to have Selective Catalytic Reduction ("SCRs") and scrubbers in place by December 31, 2013 and October 1, 2013, respectively. The Company's analyses have shown that installation of such equipment on these units will not be economical for customers across a wide range of economic scenarios even if no additional controls are required by further regulations. As a result, the Company requests that the Commission grant the Company's request for decertification of Plant Branch Units 1 & 2, effective on the required compliance dates specified under the Multipollutant Rule.

Plant Mitchell Unit 4C is a 33 MW oil-fired combustion turbine ("CT"). In December 2009, the unit experienced a significant equipment failure and the Company made the economic decision to delay repairing the unit. Weighing reliability considerations, age of the unit, challenges associated with repairs, and the potential for more stringent environmental regulatory requirements, the Company requests that the Commission also approve the decertification of Plant Mitchell Unit 4C.

As a part of the request to decertify the Plant Branch Unit 1 and 2 and Mitchell Unit 4C, the Company is requesting that the Commission reclassify the remaining net book values of Plant

PUBLIC DISCLOSURE

Branch Units 1 & 2 and Plant Mitchell Unit 4C as of their respective retirement dates to regulatory asset accounts and to amortize such regulatory asset accounts over a period equal to the respective unit's remaining useful life approved in Docket No 31958. The Company also requests that in accordance with Docket No. 31958 the Commission approve a three year recovery period (beginning January 2014) of approximately **REDACTED** of Plant Branch Units 1 & 2 environmental CWIP (which has been reclassified as a regulatory asset) and approve a three year recovery period (beginning January 2014) for any remaining, unusable M&S inventory remaining at the unit retirement dates which will be reclassified to a regulatory asset.

The Company is also requesting certification of the four PPAs identified through the 2015 RFP. As discussed above, significant uncertainty remains regarding the ultimate impact of currently pending and anticipated environmental regulations. As a result, the Company is not able to make final decisions regarding the economics of controlling approximately 2,600 MW of generating capacity and is also uncertain whether any needed controls can be installed given regulatory timelines. However, given what is currently known about such regulations and based on its analyses of potential outcomes, the Company believes it is reasonable to expect that approximately 600 MW of capacity will be controlled or switch fuels by 2015 and that the remaining capacity, approximately 2,000 MW, will be unavailable in 2015.

In light of the Company's concerns regarding resource availability in 2015, the Company initiated the 2015 RFP to help assure supplies are adequate to meet the Company's planning reserve margin target. The 2015 RFP was conducted with the oversight of Commission Staff and the Independent Evaluator ("IE") and in full compliance with the Commission's RFP rules. The RFP resulted in the selection of a portfolio of four resources, and the Company subsequently entered into PPAs in connection with these resources. The four PPAs allow for an early termination on or before March 27, 2012 in the event that the Company determines such resources are not needed in light of the final Utility MACT. As was demonstrated through the 2015 RFP, these four resources represent the best cost option for meeting the resource needs of the Company in the 2015 timeframe and should be certified by the Commission. However, it should be noted that even with the additional generation capacity obtained through the 2015 RFP, electricity reliability will be at risk in 2015 if the unrealistically short compliance timeframe associated with the Utility MACT rule is not extended.

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The Company continues to pursue cost effective Demand Side Management ("DSM") and Energy Efficiency ("EE") measures that will benefit its customers. The Company's current DSM portfolio consists of 16 demand response programs, EE programs, pricing tariffs, and other activities. The Company projects that over the next 10 years these programs will reduce capacity requirements by approximately 2,600 MW.

The Company also continues to actively pursue cost effective renewable resources. For example, the Company has instituted the SP-1 tariff to procure solar resources for the Premium Green Energy Product and has instituted an additional RFP process to procure 1,000 kW of solar installed capacity to supply the Green Energy Program. Finally, the Company proposed the 2015 Large Scale Solar Proposal ("LSS") on June 24, 2011 to procure an additional 50 MW of solar resources. This proposal was approved by the Commission on July 22, 2011.

In addition to the existing qualifying facilities ("QF") and renewable resources serving the Company through the standard offer contracts approved by the Commission, the Company has also received notice through the 2015 RFP of the intention of approximately 250 MW of new QF and renewable capacity that intends to participate in meeting the needs in 2015. The Company will enter into contracts with these entities once the certification of the 2015 PPAs has concluded and the proxy price has been set.

However, despite theses significant DSM and renewable resources, the PPAs identified through the RFP remain necessary to ensure reliable service in 2015. The Company's Application also includes the 2011 IRP Update, which supports the requests made by the Company in this Application and the Company requests approval of this IRP Update. The IRP Update includes (1) an updated load and energy forecast; (2) an updated fuel forecast; (3) the 2011 Environmental Compliance Strategy ("ECS"); (4) the 2011 Unit Retirement Study; and (5) an updated Needs Assessment. The challenges posed to the Company by the pending environmental regulations discussed in this Application are significant, but the Company believes that its plan as described in this Application best addresses the challenges and uncertainty in a manner that will help provide for continued reliable and cost-effective service for its customers, and the Commission should approve the Company's requests as described in more detail below.

Mr. WHITFIELD. Thank you.

Mr. McKinney, you are recognized for 5 minutes.

STATEMENT OF JON W. MCKINNEY

Mr. MCKINNEY. Thank you, Mr. Chairman and Ranking Member and members of the subcommittee, and thank you for the opportunity to appear before the committee.

I am used to being on the other side of the bench listening to the many different perspectives. You asked for my perspective on the impact of a number of new EPA regulations affecting the power sector, so I would like to share with you what I know about these impacts and the environmental regulations that have already taken place in West Virginia and my overreaching concern that the pace of these additional requirements does not allow sufficient time to evaluate their potential impacts on reliability or for cost-effective implementation.

I am an economic regulator, and it is my sworn duty to balance the interests of ratepayers, utility companies and the State. That is a tough assignment. We regularly hear many passionate pleas from industrial customers and residential customers who have to live on fixed incomes. We have heard these arguments recently from power companies as they installed new equipment to comply with existing environmental requirements. According to EPA's Acid Rain database, 1990 power plants in West Virginia emitted 970,000 tons of SO2. In 2010, the emissions were reduced to 110,000 tons, an 89 percent reduction.

To make these improvements, our electric industry has spent some $4 billion on environmental controls and the costs had to be passed on to our ratepayers. Even though West Virginia has relatively low electric rates, those rates have increased by 40 percent in recent years. And although I am concerned about cost of compliance, I am equally concerned about reliability. The plants that have been equipped with modern controls are generally the largest and newest plants but there are many smaller plants in West Virginia, and those plants provide not only generation but make the grid more stable. As a result of the EPA's proposal, many of these plants are expected to retire. One utility has already announced three plants in West Virginia totaling over 1,800 megawatts will retire by 2014.

My concern with both reliability and ratepayer costs will be negatively impacted by the new EPA rules led me to introduce a resolution at the July NARUC meeting that promotes increased flexibility for implementation of EPA rulemakings. That resolution was passed and is now the official policy of the National Association of Regulatory Utility Commissioners. Briefly, the resolution recognizes that by providing great flexibility, closer coordination with State and federal partners, EPA programs can achieve the same environmental goals at a lower cost to customers and without compromising reliability. Flexibility in the schedule of implementation of EPA regulations can lessen rate increases because of improved planning, selection of correction design to address multiple requirements, greater use of energy efficiency and demand-side resources, and orderly decision-making. Recently, several regional reliability organizations submitted comments to EPA echoing these concerns. Their comments are attached to my written testimony.

The impact of these rules goes far beyond the utility sector itself and could threaten the recovery of the broader economy. The American Coalition of Clean Coal Electricity recently asked NERA to model economic impacts of the Transport and MACT Rule. Overall, the analysis shows that in 2016 electric rates will increase by 11.5 percent in the United States and 12.9 percent in West Virginia. Moreover, net job losses are projected to be 1.44 million jobs in the total United States and 38,500 in West Virginia.

Cost feasibility and reliability impacts of EPA regulations have not been thoroughly examined and consequences of implementing these requirements without adequate review could be irreparable. Greater flexibility could preserve both electric reliability and mitigate additional rate increases. With these challenges in mind, I urge you to consider legislation such as the TRAIN Act and to include pertinent portions of the NARUC resolution in the bill. Thank you.

[The prepared statement of Mr. McKinney follows:]

COMMISSIONER JON W. MCKINNEY

Testimony Summary

- I introduced a NARUC Resolution that promotes increased flexibility for the implementation of EPA Rules by:
-
  - Allowing utilities to coordinate the closure and/or retrofitting of existing electric generating units in an orderly manner;
  - Allowing regulatory options for units that are necessary for grid reliability that commit to retire or repower; and
  - Asking FERC work with the EPA to develop a process that requires generators to provide advanced notice.
- Pointing out that PJM, MISO, SPP, NY ISO, and ERCOT submitted comments requesting a "safe harbor" (i.e. not face penalties for violation of the EPA rule) if they provide the Regional Transmission Organization with notice of their intended shutdown at least two years before the EPA compliance deadline.
- WV has made major improvement with utilities investing $4.0+ billion dollars with a 89% reduction in SO_2. Aggregated capital cost of new rules will exceed another $2.0+ billion dollars.
- I am concerned by the suggested impacts to WV and the US of latest CASPR and MACT rules (as indicated by recent NERA analysis or EEI retirement summary)
  - Increased electricity cost of 12.9% for WV and 11.5% for US
  - Net job losses of 38,500 for WV and 1.44M for US
  - Total US cost of $184B for US
  - FERC recently projected 81GW of coal generation retirement vs. 11GW projected by EPA (Announced retirements already at 44GW)
- Consider passage of the TRAIN Act and include pertinent portions of the NARUC resolution in the bill.

Mr. Chairman, thank you for the opportunity to appear before the Committee on this extremely important issue. I am Jon McKinney, a Commissioner for the Public Service Commission (PSC) of West Virginia and Chair of the Clean Coal Subcommittee of NARUC. My background is in engineering and business prior to being appointed a Commissioner.

The West Virginia Commission has a broad scope of duties that includes regulation of all utilities in WV (electricity, natural gas, water and sewer, telecom and some cable) as well as solid waste, gas pipeline, transportation (taxis, buses, trucking), graveyards, and railroads. Our work touches many of the most vital services our citizens depend on every day. Each year we decide 2700+ cases, issue 5000+ orders and handle 10000+ informal and formal complaints.

I am used to being on the other side of the bench, listening to many different perspectives. You have asked for my perspective on the impact of a number of new EPA regulations affecting the power sector. So I'd like to share with you what I know about the impacts that environmental regulations have already had in WV, and my overarching concern that the pace of these additional requirements does not allow sufficient time to evaluate their potential impacts on reliability, or for cost-effective implementation.

I am an economic regulator and it is my sworn duty to balance the interests of ratepayers, utility companies and the State. That is a tough assignment. We regularly hear many passionate pleas from industrial customers that they will be driven out of business if electricity rates increase too much, or from residential customers who are trying to balance budgets or live on fixed incomes. We have heard these arguments frequently in recent years as power companies have installed new equipment to comply with existing environmental requirements. According to EPA's Acid Rain database, in 1990 power plants in WV emitted nearly 970,000 tons of SO2.

By 2010, those emissions were reduced to less than 110,000 tons, an 89% reduction state-wide. WV has made remarkable progress in assuring that the air is clean for its own citizens and our neighbors.

To make these improvements, our electric industry has spent some $4.0+ billion dollars on environmental controls, and that cost has been passed on to the ratepayers. Even though WV has relatively low electric rates, those rates have increased by nearly 40% in recent years. And although I am concerned about the cost of compliance, I am equally concerned about reliability. The plants that have been equipped with modern pollution controls are generally the largest and newest plants, but there are many smaller plants throughout WV and other states that not only provide generation, but also assure that we have a stable electric grid. As a result of the EPA's proposed and final rules, many of these plants are expected to retire, quite abruptly, over the next few years. One utility has announced that at least three plants in WV, totaling over 1800 MW, will retire by 2014 if all of EPA's rules become effective. In addition, an estimate of the capital required to make the additional modifications needed to meet the new proposed EPA rules is $2.0+B.

The WV Commission is tasked with ensuring that the WV consumers receive reliable power. We have learned recently that reliability is king and that concerns about reliable service are one of the greatest concerns to customers. During a recent severe blizzard in southern WV over the Christmas holidays, during peak demand, power was interrupted for many residents for an extended period. Obviously, in very cold weather this is a dangerous situation and we and the electric companies were swamped with complaints from ratepayers, county commissions, legislators, and emergency response providers. My concern is that the new EPA rules will denigrate reliability leading to more major interruptions during peak electrical usage.

My two-fold concerns for both reliability and ratepayer cost that will be negatively impacted by currently promulgated and proposed EPA rules led me to introduce a Resolution at the July NARUC meeting that promotes increased flexibility for implementation of EPA rule makings. That resolution was passed and is now the official policy of NARUC. The Resolution is attached, is summarized below and specifically asks that State Commissioners promote State and federal environmental and energy policies that will enhance the reliability of the nation's energy supply and minimize cost impacts to consumers.

Reliable energy supply is vital to support the nation's future economic growth, security, and quality of life.

There are three key elements that the EPA must successfully manage when implementing the new and proposed regulations to ensure continued reliability on the nation's electric grid while lessening generation cost increases upon our Nation's ratepayers during these difficult economic times, should they move forward with implementation of the regulations currently under consideration. These elements which are all equally important are: (1) flexibility; (2) coordination with utilities; and (3) coordination with State and federal regulators.

(1) Flexibility: A retrofit timeline for multimillion dollar projects may take up to five-plus years, considering that the retrofit projects will need to be designed to address compliance with multiple regulatory requirements (some of which are not finalized and may change mid-design) and require several steps that may include, but are not limited to: utility regulatory commission approval, front-end engineering, environmental permitting, detailed engineering, construction and startup. Timelines may also be lengthened by the large

number of multimillion dollar projects that will be in competition for the same skilled labor and resources throughout the Nation.

Flexibility with the implementation of EPA regulations can lessen generation cost increases because of improved planning, selection of correct design for the resolution of multiple requirements, greater use of energy efficiency and demand-side resources, and orderly decision-making. Additionally, some generators that will be impacted by the new EPA rulemakings are located in constrained areas or supply constrained areas and will need time to allow for transmission or new generation studies to resolve reliability issues. The North American Electric Reliability Corporation (NERC) and regional RTOs will need time to study reliability issues associated with shutdown or repowering of generation. Flexibility will allow time for these needed studies.

2. Coordination: Close coordination between the various federal and State regulatory bodies and agencies will also be necessary for continued grid reliability. The Federal Energy Regulatory Commission (FERC), through its oversight of NERC, has authority over electric system reliability, and is in a position to require generators to provide sufficient notice to FERC, system operators, and State regulators of expected effects of forthcoming health and environmental regulations on operating plants to allow an opportunity for meaningful assessment and response to reliability claims.

The Resolution asks Commissioners to support efforts to promote State and federal environmental and energy policies that will enhance the reliability of the nation's energy supply and minimize cost impacts to consumers by:

- Allowing utilities to coordinate the closure and/or retrofitting of existing electric generating units in an orderly manner that will ensure the continued supply of electricity and that will allow power generators to upgrade their facilities in the most cost effective way, while at the same time achieving attainable efficiency gains and environmental compliance.

- Allowing regulatory options for units that are necessary for grid reliability that commit to retire or repower.
- Allowing an EPA-directed phasing-in of the regulation requirements.
- Establishing interim progress standards that ensure generation units meet EPA regulations in an orderly, cost-effective manner.

- Encourages utilities to plan for EPA regulations, and explore all options for complying with such regulations, in order to minimize costs to ratepayers.

- Asking that FERC and EPA work to develop a process that requires generators to provide notice to FERC, system operators, and State regulators of the expected effects of forthcoming EPA regulations on operating plants to allow an opportunity for meaningful discussion, assessment and response to reliability issues. Additionally we suggested that NARUC and State Commissions should actively coordinate with their environmental regulatory counterparts, FERC, and the electric power sector ensuring electric system reliability and encourage the use of all available tools that provide flexibility in EPA regulation requirements reflecting the timeline and cost efficiency concerns embodied in this resolution to ensure continuing emission reduction progress while minimizing degradation of reliability, capital costs, rate increases and other negative economic impacts while meeting public health and environmental goals.

Recently, several regional reliability organizations submitted comments to EPA echoing these concerns. In comments submitted on the utility MACT rule August 4, the Southwest Power Pool, ERCOT, PJM, the Midwest Independent Transmission System Operator, and the New York Independent System Operator, all requested a "safe harbor" for units that have to retire or which may be uneconomic to retrofit, but which may be critical for system reliability due to local transmission constraints. All of these organizations indicated that an additional two years or more might be needed to assure that such retirements do not compromise the reliability of the electricity grid. Their comments are also attached to my written testimony.

Lack of implementation time will leave utilities with only two choices both of which have significant negative reliability impacts: either scale back on generation to meet rulemaking requirements (in some cases as much as 50%) or shutdown prematurely. Local or regional congestion will be a major issue in many areas and that will take multiple years to resolve. As an example, DC has been working for years to shutdown two old coal plants but due to congestion issues still have them in a "must run" category. This leads to following major concerns:

- Compliance Deadlines. EPA is not providing sufficient time to design, permit, and install major emissions control technologies on large amounts of existing coal-fired capacity that are necessary to comply with EPA's Cross-State Air Pollution Rule (beginning in 2012, with more stringent limits in 2014) and the proposed Utility MACT Rule (by the end of 2014 or by end of 2015).

- Major Capital Expenditures, Mostly Before 2015. There would be much more capital spent in the U.S. to comply with these new EPA rules by 2020, as compared to the amounts that were spent on all utility air pollution controls over the previous 20 years.

- Significant Power Plant Retirements due to the Combination of the High Costs of Compliance and the Short Deadlines. FERC recently projected 81GW of coal generation retirement vs. 11GW projected by EPA. The NERA analysis project four times the amount of retires as EPA. The total amount of announced coal generating plant retirements (including all reasons) are 44GW or 13% of the total coal-fired generation. Clearly the immediate impact of the regulations is far greater than expected.

- Electric Grid Reliability Problems during 2014-2016. This impact is projected to occur due to the large number of retirements plus the substantial amount of idled capacity due to insufficient time to design, permit, and install major emissions controls as well as the wide-scale unit outages that are required to "tie-in" these major new emission controls. These greatest capacity reductions will probably occur in the PJM region.

- Very High Electricity Rate Increases Due to High Capital Costs of Compliance and New Replacement Capacity. In WV and the Midwest these rate increases will hit electricity intensive manufacturing particularly hard, leading to industrial plant shutdowns and substantial job losses. It will also be disproportionately borne by consumers in some of the poorest rural counties in Appalachian Region states where there are many customers who are unemployed or on fixed incomes.

The impact of these rules goes far beyond the utility sector itself, and could threaten recovery in the broader economy. The American Coalition of Clean Coal Electricity (ACCCE) recently asked NERA Economic Consulting to model the economic impacts of the proposed CATR and MACT Rule together. Overall the analysis shows that in 2016 electricity rates will increase by 11.5% in the US generally, and by another 12.9% in WV. Moreover, net job losses are projected to be 1.44 million for the total US and 38,500 for WV. A large portion of these losses will be borne by states and rural counties that are already experiencing much higher electricity rates due to previous environmental investments. Though there will be some temporary gains in employment due to construction of new pollution control and new gas-fired generation, these will be more than offset by (1) direct losses at shuttered coal-fired plants and related supply chain losses in mining and transportation; (2) reduction of industrial activity (and hence jobs) in these same states as higher electricity rates result in industrial plant shutdowns and output cuts; (3) indirect losses occurring as local supporting employment dwindles in the states and localities experiencing these losses; and (4) wide-scale job losses across the U.S. as consumers and business shouldering higher electricity rates cut back on consumption of other goods reducing GDP overall and jobs in a variety of industries. I believe that more analysis needs to be done after the two rules are finalized and before implementation. If such impacts continue to be shown, they are unacceptable in the current fragile state of our economy.

The costs, feasibility, and reliability impacts of EPA's regulations have not been thoroughly examined, and the consequences of implementing these requirements without adequate review could be irreparable. We have just recently seen the dramatic consequences of a major power outage in the western US, where 1.4 million people were without power and, in addition to many other consequences, millions of gallons of sewage flooded the San Diego harbor. We cannot afford to risk the health and safety of millions of Americans by compromising the security of our electricity grid, and should not burden electricity customers with excessive costs by inflexible implementation of environmental regulations. Greater flexibility would preserve electric reliability and mitigate additional rate increases.

So, with these challenges and solutions in mind, I urge you to consider passage of the TRAIN Act, and to include pertinent portions of the NARUC resolution in the bill. At a minimum, before any new EPA regulation is implemented or promulgated, DOE and FERC should be required to obtain information about unit retirements and operational changes by a date certain so that they can properly analyze local and regional reliability issues and the results can be considered by the Congress.

Thank you.

Attachments

- NARUC Resolution
- NERA analysis
  - Summary of proposed CASPR and MACT Rules
  - Average Regional Electricity Price Increases Map
  - Net Employment Losses Table
- Train Wreck slide
- Coal Fleet Retirement Announcements
- SPP letter to EPA
- Joint RTO letter to EPA
- ERCOT letter concerning reliability
- PJM letter to EPA

Resolution on Increased Flexibility for the Implementation of EPA Rulemakings

WHEREAS, The Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution on the *Role of State Regulatory Policies in the Development of Federal Environmental Regulations* on February 16, 2011; including the following statements:

- **WHEREAS**, NARUC at this time takes no position regarding the merits of these EPA rulemakings; *and*
- **WHEREAS**, Such regulations under consideration by EPA could pose significant challenges for the electric power sector and the State Regulatory Commissions with respect to the economic burden, the feasibility of implementation by the contemplated deadlines and the maintenance of system reliability; *and*

WHEREAS, NARUC wishes to continue to advance the policies set forth in the resolution as it relates to the proposed EPA rulemakings concerning the interstate transport of sulfur dioxide and nitrogen oxides, cooling water intake, emissions of hazardous air pollutants and greenhouse gases, release of toxic and thermal pollution into waterways, and management of coal combustion solids; *and*

WHEREAS, NARUC recognizes that a reliable energy supply is vital to support the nation's future economic growth, security, and quality of life; *and*

WHEREAS, There are many strategies available to States and utilities to comply with EPA regulations, including retrofits and installation of pollution control equipment, construction of new power plants and transmission upgrades to provide resource adequacy and system security where needed when power plants retire, purchases of power from wholesale markets, demand response, energy efficiency, and renewable energy policies – the collection of which can be implemented at different time frames by different interested parties and may constitute lower cost options that provide benefits to ratepayers; *and*

WHEREAS, A retrofit timeline for multimillion dollar projects may take up to five-plus years, considering that the retrofit projects will need to be designed to address compliance with multiple regulatory requirements at the same time and requiring several steps that may include, but are not limited to: utility regulatory commission approval, front-end engineering, environmental permitting, detailed engineering, construction and startup; *and*

WHEREAS, Timelines may also be lengthened by the large number of multimillion dollar projects that will be in competition for the same skilled labor and resources; *and*

WHEREAS, NARUC recognizes that flexibility with the implementation of EPA regulations can lessen generation cost increases because of improved planning, selection of correct design for the resolution of multiple requirements, greater use of energy efficiency and demand-side resources, and orderly decision-making; *and*

WHEREAS, Some generators that will be impacted by the new EPA rulemakings are located in constrained areas or supply constrained areas and will need time to allow for transmission or new generation studies to resolve reliability issues; *and*

WHEREAS, The North American Electric Reliability Corporation (NERC) and regional RTOs will need time to study reliability issues associated with shutdown or repowering of generation; *and*

WHEREAS, NARUC recognizes that flexibility will allow time for these needed studies, *and*

WHEREAS, The Federal Energy Regulatory Commission (FERC), through its oversight of NERC, has authority over electric system reliability, and is in a position to require generators to provide sufficient notice to FERC, system operators, and State regulators of expected effects of forthcoming health and environmental regulations on operating plants to allow an opportunity for meaningful assessment and response to reliability claims; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2011 Summer Committee Meetings in Los Angeles, California, supports efforts to promote State and federal environmental and energy policies that will enhance the reliability of the nation's energy supply and minimize cost impacts to consumers by:

- Allowing utilities to coordinate the closure and/or retrofitting of existing electric generating units in an orderly manner that will ensure the continued supply of electricity and that will allow power generators to upgrade their facilities in the most cost effective way, while at the same time achieving attainable efficiency gains and environmental compliance; *and*

- Allowing regulatory options for units that are necessary for grid reliability that commit to retire or repower; *and*

- Allowing an EPA-directed phasing-in of the regulation requirements; *and*

- Establishing interim progress standards that ensure generation units meet EPA regulations in an orderly, cost-effective manner; *and be it further*

RESOLVED, That commissions should encourage utilities to plan for EPA regulations, and explore all options for complying with such regulations, in order to minimize costs to ratepayers; *and be it further*

RESOLVED, That FERC should work with the EPA to develop a process that requires generators to provide notice to FERC, system operators, and State regulators of expected effects of forthcoming EPA regulations on operating plants to allow an opportunity for meaningful assessment and response to reliability issues; *and be it further*

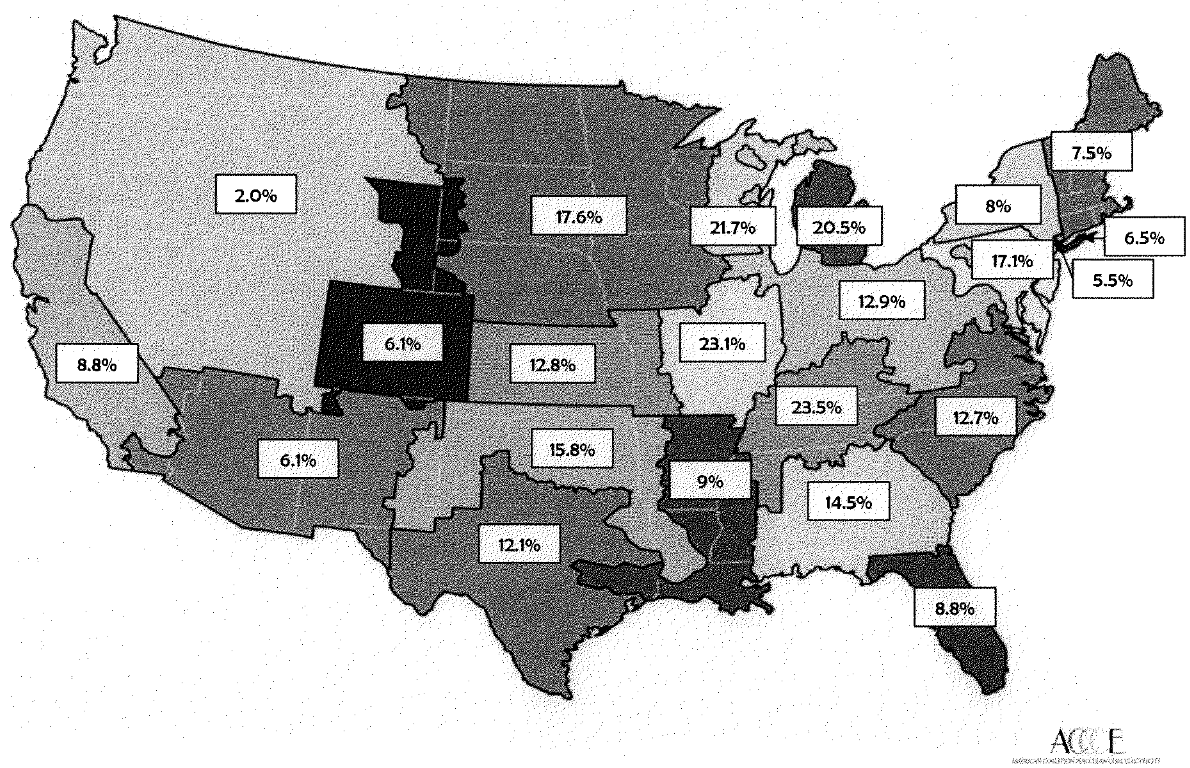
RESOLVED, That NARUC and its members should actively coordinate with their environmental regulatory counterparts, FERC, and the electric power sector ensuring electric system reliability and encourage the use of all available tools that provide flexibility in EPA regulation requirements reflecting the timeline and cost efficiency concerns embodied in this resolution to ensure continuing emission reduction progress while minimizing capital costs, rate increases and other economic impacts while meeting public health and environmental goals.

Sponsored by the Subcommittee on Clean Coal and Carbon Sequestration and the Committees on Electricity and Energy Resources and the Environment
Adopted by the NARUC Board of Directors July 20, 2011

PROPOSED CATR AND UTILITY MACT RULES
June 2011

	NERA INITIAL ANALYSIS	EPA ANALYSIS
MODELS	NEMS, REMI and NERA Retirement Model	IPM
EMISSION CONTROLS	531 GW	354 GW
ANNUALIZED COST	$17.8 billion	$14.4 billion
TOTAL COST (PRESENT VALUE)	$184 billion	$124-$168 billion
U.S. ELECTRICITY PRICE	11.5 percent average increase in 2016	1.5 percent increase in 2014 for CATR and 3.7 percent increase in 2015 for MACT
REGIONAL ELECTRICITY PRICES	Regions covering all or part of 24 states have average price increases of 12.1 percent to 23.5 percent in 2016	Regional impacts of 0 to 5 percent in 2014 for CATR and 1.4 to 7.1 percent in 2015 for MACT
ADDITIONAL COAL RETIREMENTS	47.8 GW	11 GW
COAL DEMAND	10 percent reduction in 2016	3 percent reduction in 2015
NATURAL GAS PRICES	17 percent increase	Less than 2 percent increase
NATURAL GAS EXPENDITURES	$8.2 billion/yr higher costs for residential, commercial and industrial sectors	No information provided by EPA
U.S. EMPLOYMENT	Economy-wide net employment loss of 1.44 million job-years by 2020	For MACT, a one-time increase of 30,900 construction jobs, as well as 9,000 in possible jobs/year in the electric sector. No information provided for CATR.

Average Regional Electricity Price Increases in 2016 due to Transport Rule and MACT Proposals



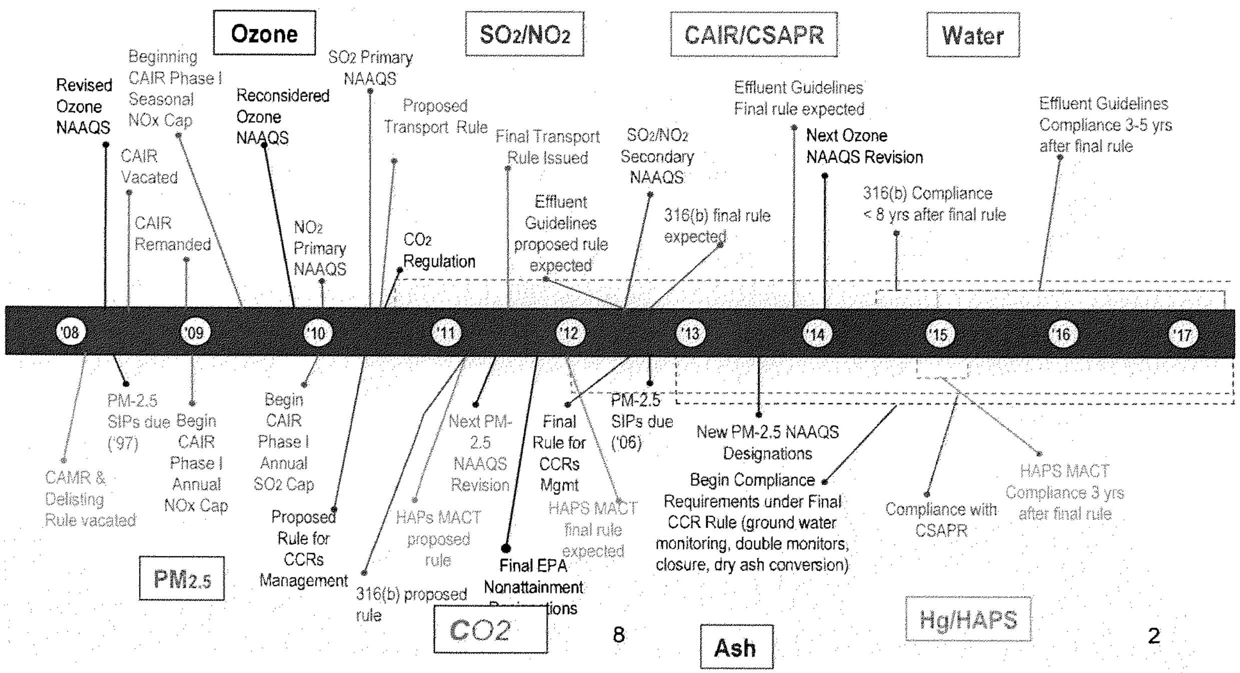
ACCCE
AMERICAN COALITION FOR CLEAN COAL ELECTRICITY

Net Employment Losses Due to EPA's Proposed Transport and MACT Rules
June 2011

	Net Employment Losses 2013 – 2020 (Job-Years)
FLORIDA	135,000
ILLINOIS	48,000
INDIANA	51,500
IOWA	26,500
MICHIGAN	40,000
MINNESOTA	12,500
MISSOURI	76,000
MONTANA	21,000
NEW MEXICO	9,000
NORTH CAROLINA	47,000
OHIO	53,500
PENNSYLVANIA	59,000
VIRGINIA	50,000
WEST VIRGINIA	38,500
WISCONSIN	24,500
TOTAL FOR 15 STATES ABOVE	692,000
U.S. TOTAL	1.44 million

"Net" employment impacts take into account both job gains and job losses. Job losses outnumber job gains by four to one over the period 2013-2020. Employment numbers are rounded.

US EPA Regulatory Agenda Impacting Coal-Fired Generating Plants



-- updated from Wegman (EPA 2003)

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Coal Fleet Retirement Announcements

Following is a summary of announced retirements of specific coal plants under which approximately 44,000 MW of generation (or 13% of the 339 GW of total coal-fired generation in 2010) will be retired between 2010 and 2022.[1] Some units will be replaced with natural gas generation.[2]

Company	Total MW	State	Year(s) Built	Year(s) Will Retire	Units Retiring/Notes
AEP[3]	6,664	Various	1944-1980	2012-2014	27 units in 6 states (OH, WV, VA, IN, KY, TX)
AES	188	NY	1951, 1953	2011	2 units
Alliant	428	IA	1921-1968	2010	12 units
Ameren[4]	923	MO	1953-1961	2022	4 units
APS[5]	634	AZ	1963, '64	2015	3 units (Four Corners)
Black Hills	44	CO	1955, '59	2013	2 units
Consumers	971	MI	1952-1958	2017	7 units
Dominion[6]	2,400	various	1952-1992	2013-2017	17 units in 3 states (MA, IN, VA)
DTE[7]	169	MI, CA	1952, '87, '89	2010-2011	4 units
Duke[8]	3,584	various	1940-1969	2011-2018	30 units in 4 states (NC, SC, IN, OH)
Dynegy	489	IL	1953-1959	2011-2013	4 units
Edison Int'l[9]	371	IL	1955	2010	2 units
Empire District	88		1950, 1954	2018	2 units
Exelon	895	PA	1954, 1960	2011-2012	3 units
First Energy[10]	2,004	OH	1950-1968	2010-2012	12 units
GenOn	482	VA	1949-1957	2012	5 units; Potomac River Generating Station
Madison G&E	178	WI	1938-1961	2010-2012	5 units
NiSource[11]	384	IN	1956, '59, '70	2012	3 units
NRG[12]	440	DE	1951-1970	2010-2013	4 units
NV Energy	342	NV	1965, '68, '76	2016	3 units
Otter Tail	130	MN	1959, 1964	2017-2018	2 units
PGE	601	OR	1980	2020	Will retire Boardman plant 20 years early
Progress[13]	2,532	NC, FL	1951-1972	2011-2020	13 units
Southern[14]	10,120	GA	1963-1967	2011-2013	5 units
TransAlta[15]	1,460	WA	1971	2019-2024	2 units (Centralia)
TVA[16]	4,294	various	1952-59	2012-2117	24 units in 3 states (TN, AL, KY)
WE Energies	112	MI	1964, 1966	2010	2 units
Xcel[17]	1,548	CO, MN	1951-1968	2010-2022	12 units
Others[18]	1,835	various	1948-2004	2010-2026	
	44,310				

[1] Retirements are taking place for a variety of reasons, including plant age, fuel prices (i.e., low natural gas prices), decreased demand, consent decrees and the settlement of EPA complaints, the projected cost of complying with the pending EPA regulations, etc. Because some plant closure details and/or plans for replacement generation have not been finalized, it is not possible to determine the exact number of closures, the mix and quantity of generation replacing the retiring coal units, or the exact amount of emissions reductions.
[2] To the degree that retiring coal plants are replaced with natural gas generation, mercury and SO_2 emissions will be virtually eliminated and CO_2 emissions reduced by almost half at those units.

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[3] As part of its plan for complying with EPA regulations (released 6/09/11), AEP announced that it would be retiring 6,000 MW of coal-fired generation—some of which will be replaced with natural gas units—belonging to the following AEP subsidiaries: Kentucky Power, Indiana Michigan Power, Southwestern Electric Power, Ohio Power, Columbus Southern and Appalachian Power . Some of the plant retirements are part of a settlement agreement with EPA.

[4] Ameren, in Feb. 2011 IRP filing in MO, indicated it would likely close Meramec 1-4 due to the cost of meeting pending EPA regulations.

[5] As part of a complaint settlement with EPA in November 2010, APS agreed to retire 3 units and purchase and retrofit 2 others at the Four Corners plant. The agreement will lead to the following reductions: plant capacity by 560 MW; NOx emissions by 36%; mercury emissions by 61%; particulate matter by 43%; CO_2 emissions by 30%; SO_2 emissions by 24%. It will also allow plant to remain compliant with state and federal environmental standards and reduce the carbon footprint in the region. Buying the 2 units for $294 million was "substantially less" than the other alternatives and saves customers "nearly $500 million over the next best alternative"

[6] Dominion is retiring 11 units due in part to cost of complying with the pending EPA regs (Salem Harbor, State Line, Chesapeake, Yorktown), and 4 units are being retired due to low natural gas prices. 3 units (Altavista, Hopewell, and Southhampton) are being converted to biomass and 2 to natural gas (Bremo Bluff, Yorktown). Some of these closures were included in a September 1, 2011, IRP filing.

[7] DTE Energy Services has agreed to covert 2 coal-fired facilities to biomass—the Port of Stockton Energy Facility and the Mount Poso Cogeneration Plant (co-owned with Red Hawk Energy)

[8] The Beckjord 6 unit, which is co-owned with AEP subsidiaries Columbus Southern and Dayton Power & Light, is included in the Duke total. As part of its overall coal-fleet transition strategy, Duke announced an agreement in 2008 to retire 800 MW of coal-fired power in exchange for building new 825 MW clean coal facility at Cliffside. It is not clear which plant retirements relate to this announcement, with the exception of Cliffside 1-4. Duke also agreed to make the new facility carbon neutral by 2018 by offsetting approximately 5½ million tons of CO_2/year) through the following means: depending more on nuclear power, further reducing power generated by coal-burning units, and using energy efficiency programs, carbon free tariffs and other "mitigation projects." Duke's permit for the new plant allows cost recovery. The new unit will: remove 99% of SO_2, 90% of NOx emissions and cut mercury emissions by 50%; be built to accommodate installation and operation of carbon control technologies; significantly minimize thermal impacts to the local river; and, generate wall board quality gypsum from the wet scrubber

[9] Edison International is closing the Will County units as part of mercury agreement with IL, and has also agreed to install SO_2 and NOx controls on all Midwest Gen plants.

[10] In August 2010, FirstEnergy announced that it would retire all or part of 2 coal-fired peaking plants (Lake Shore and Ashtabula)—and reduce operations at 2 other plants (Bay Shore and Eastlake)—due to decreased demand, plant age, etc. The units comprised 7% of total production in 2009. FE is retiring 2 other units (R.E. Burger) under a consent decree with EPA

[11] Retirement of Dean Mitchell units is part of a consent decree w/ EPA

[12] NRG retired Somerset Station 1 (74 MW, 1951 [**2010**]);

[13] As part of its overall coal-fleet transition strategy, Progress announced an agreement in December 2009 to retire 30% of its NC fleet (11 plants or approximately 1,500 MW of total capacity), replace some with natural gas plants, build new 950-MW natural gas plant at H.F. Lee plant site and build additional new 600-MW natural gas plant at Sutton Plant to replace coal generation being retired in order to maintain reliability. Progress' remaining NC plants are scrubbed (spent $2 billion installing state-of-the-art control on remaining coal generation). The retirement of 2 units in FL (Crystal River 1 & 2) depends on getting approval to move forward with a new nuclear plant.

[14] Southern (Georgia Power) is retiring the plants due primarily to the cost of complying with pending EPA regs. Southern has announced plans to convert the Mitchell plant to biomass (currently on hold), and that it may also retire Yates 6 & 7 (355 MW each, 1974) plants. On August 4, 2011, Southern filed comments that it expects to retire 4,000 MW of coal-fired generation—and repower approximately 4,700 MW of coal and oil-fired generation to natural gas and other fuels—as a result of compliance with the pending EPA regs, but has not specified which plants would be affected.

[15] Under agreement with state, TransAlta will install SNCRs on the units in 2013, invest $55 million on energy efficiency and clean energy technology development, and be allowed to sell power in-state from the plants under long-term contracts until they close.

[16] As part of settlement agreement with EPA (04/14/2011), TVA agreed to retire or idle the following coal plants: Johnsonville 1-10, John Sevier 3-4 and Widows Creek 1-6. In addition, TVA has agreed to spend $3-$5 billion in additional pollution control equipment for its remaining coal plants and $350 million on air pollution reduction and energy efficiency projects, as well as pay a $10 million civil penalty. Separately, TVA announced on 8/24/10 it would retire Shawnee 10 and John Sevier 1 & 2.

[17] As part of its overall coal-fleet transition strategy, Xcel announced a plan In August 2010 for its Colorado units only, in response to state law. Xcel will retire Cherokee 1-4 and Valmont, will spend $1.3 billion to convert coal-fired power plants to natural gas plants ($225 million savings compared to retrofitting the existing plants), and will retrofit 950 MW of coal-fired generation with modern emission control technologies. These actions will reduce Xcel's CO_2 emissions 20% by 2020. As part of 2007 IRP, Xcel agreed to add 1,000+ MW of renewable energy (which will allow it to meet the state RPS), to reduce demand by 694 MW through energy efficiency programs, and to retire Arapahoe 3 & 4 and Cameo 1 & 2. Xcel retirements also include 2 units operated by Northern States (Black Dog).

[18] Reflects coal plant retirements by the following power entities (state located in, owner, total MW, year built and [year of retirement] are shown in parenthesis): Hunlock 3 (PA, UGI Development Co., 45 MW; 1959 [**2010**]), Lakeside 6 & 7 (IL, City Water Light & Power, 76 MW, 1961, '65 [**2010**]), Muscatine 7 (IA, City of Muscatine, 21 MW, 1958 [**2010**]), James de Young 3 (MI, Holland Board of Public Works, 11 MW, 1951 [**2012**]), DOE Savannah River 1 & 2 (SC, U.S. DOE, 18 MW, 1952 [**2013**]), Quindaro 1 & 2 (KS, Kansas City Board of Public Utilities, 239 MW, 1965, '71 [**2026**]); Shelby Municipal 1-4 (OH, Shelby City, 37 MW total, 1948, '54, '68, '73 [**2012**]); Richard Gorsuch 1-4 (OH, American Municipal Power, 50 MW each, 1968 [**2010**]); Abbott Power Plant (IL, Univ. of Illinois, 49 MW total, 1959, '62, 2004 [**2017**]); JT Deely 1-2 (TX, CPS Energy, 871 MW, 1977-78 [**2018**]; Penn State West Campus Plant (PA, Penn State Univ., 20 MW, 1929 [**2014**]; UNC Chapel Hill Cogen 3 (NC, UNC, 28 MW, 1991 [**2020**]; Charter Street Hearting Plant 1 (WI, Univ. of Wisconsin, 10 MW, 1965 [**2010**]; Howard Down Station 7-10 (NJ, Vineland Municipal, 25 MW, 1970 [**2010**]; Utah Smelter Plant 1-3 (UT, Whitewater Valley 1-2 (VA, Richmond P&L, 94 MW total, 1955, '73 [**2011**]), Austin Northeast Station (TX, Austin Utilities, 32 MW, 1971 [**2011**]), Intl Paper (VA, 21 MW [**2010**])

SPP Southwest Power Pool

HELPING OUR MEMBERS WORK TOGETHER TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

Nicholas A. Brown, President & CEO

VIA ELECTRONIC SUBMISSION AND FIRST CLASS MAIL

July 19, 2011

Water Docket
U.S. Environmental Protection Agency
Mail Code: 4203M
1200 Pennsylvania Ave., NW
Washington, DC 20460

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Docket ID No. EPA-HQ-OW-2008-0667

National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Docket ID Nos. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2011-0044

Dear Sir or Madam:

Southwest Power Pool, Inc. (SPP) appreciates the opportunity to comment and respectfully submits the attached report entitled, "Review of the Potential Reliability Impacts of Proposed EPA Regulations Impacting Generation in the SPP Footprint", dated July 19, 2011, in response to the U.S. Environmental Protection Agency's (EPA) proposed rules issued in the above-captioned dockets. SPP's preliminary assessment is based on a similar study performed by ERCOT which found comparable results. SPP's cursory analyses identify substantial reliability and cost impacts under credible scenarios with extremely conservative inputs and assumptions, particularly in light of the recently released EPA Cross-State Air Pollution Rule (CSAPR) which was not considered in this assessment.

SPP is an Arkansas non-profit corporation with its principal place of business at 415 N. McKinley, Suite 140, Little Rock, Arkansas 72205. Currently, SPP has 64 members serving approximately 15 million customers in a 370,000 square mile service territory covering all or part of the following states: Arkansas, Missouri, Kansas, Oklahoma, Louisiana, Mississippi, Nebraska, New Mexico and Texas. SPP's members include investor-owned utilities, municipals, cooperatives, state authorities, independent power producers, power marketers, independent transmission companies, as well as a contract participant. SPP is a Federal Energy Regulatory Commission (FERC) approved Regional Transmission Organization (RTO) and administers open-access transmission services across the SPP region under the terms of SPP's Open Access Transmission Tariff. As an RTO, SPP plans for and functionally controls the transmission infrastructure committed to it and administers a competitive real-time wholesale electricity marketplace.

As outlined in the paragraphs that follow, SPP is concerned that the timeframe for implementation of the proposed rules may not provide generator operators sufficient time to bring their facilities into compliance, and they would be prohibited from operating until compliance activities can be completed. Should this occur, threats to the reliable operation of the grid will occur.

While SPP's initial assessment has focused on coal and gas units and select EPA rules similar to the ERCOT assessment, other pending requirements – carbon dioxide regulations for example – could have major impacts on future resource plans, system reliability, and economics. It is important to note this initial assessment did not consider impacts the reciprocating internal combustion engines (RICE) regulations may have on the potential loss of small units which many municipalities have relied upon. Elimination of those units could create local congestion challenges and require both transmission expansion and local programs to keep the lights on. Similarly, SPP did not consider the impact of Regional Haze requirements and the most recently published Cross-State Air Pollution Rule, which will exacerbate impacts on the system and SPP's ability to maintain adequate generating capability and reserves in the SPP footprint.

Based on this cursory assessment, which seems conservative given recent developments, it appears that EPA regulations could prevent reliable operation of the SPP RTO. Further impacts may occur, including failure to meet the requirements set forth by the North American Electric Reliability Corporation which were approved by FERC. SPP's findings and conclusions are not intended to exaggerate the system impacts, but rather to point out the possible types of adverse outcomes that may result in worst case scenarios as defined in this assessment.

SPP is concerned that the timeframe for compliance with the proposed rules, should they be approved, may be more aggressive than what can be achieved by the industry. Should this be the case it may adversely impact grid reliability due to the sudden required retirements and outages of units. At this point, SPP is aggressively monitoring several areas of its system where temporary mothballing of facilities appears possible and may lead to unstable, and hence unreliable, operating conditions. SPP encourages the EPA to work with generation owners to develop flexible compliance schedules to ensure equipment installation is completed in a timely, safe, reliable and cost-effective manner without an arbitrary deadline. Compliance plans developed in a collaborative manner may lessen the negative impact and/or prevent the unavailability of labor, parts, and other resources that may result from an arbitrary deadline. Such an approach would also ease concerns over grid instability caused by mass outages on generators to install the required equipment.

Furthermore, SPP is concerned that sufficient time will not be available to complete transmission construction activities necessary to mitigate the prohibited operation of certain generators and to complete the construction of replacement resources. As SPP becomes aware of units removed from service due to compliance with these new regulations, it will work diligently to plan and direct the transmission construction necessary to mitigate any resulting reliability issues on the SPP transmission system. However, as Transmission Customers within the region remove units from service and secure new replacement capacity, SPP is concerned as to the uncertainty of being able to identify the needed upgrades and place those new lines in service. SPP is responsible for overseeing the reliable operation of the SPP transmission system and is concerned that, in the event SPP is unable to construct the necessary lines in time and units are unable to operate due to these additional EPA restrictions, the SPP

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transmission system may be placed in an unreliable operating state or one that necessitates firm load curtailments/customer outages.

As a result of these concerns, SPP has two specific recommendations:

- First, SPP recommends that the EPA provide a gradual compliance schedule that allows the industry time to meet the proposed requirements in a reliable, safe and economic manner. Working with the industry to institute these changes will help preserve reliable system operations and also allow for a more gradual integration of the costs of compliance that could significantly mitigate reliability issues and sudden increases in consumer electricity prices.
- Second, SPP recommends that the EPA include in its rules a temporary waiver mechanism under which the affected generator owner, could seek an extension to allow for the continued operation of a generator while solutions, such as transmission expansion or demand response programs, can be assessed and approved by SPP and other transmission service providers.

Although these recommendations are based solely upon SPP's initial assessment, they appear to be prudent under any foreseeable conditions that may occur.

Please do not hesitate to contact me should you have questions or would like to request additional information.

Respectfully submitted,

Nick Brown

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cc: SPP Board of Director, Members Committee, Strategic Planning Committee
State Regulators and Federal Legislators in AR, KS, LA, MO, MS, NE, NM, OK, and TX

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units	)))))))))	**EPA-HQ-OAR-2009-0234** **EPA-HQ-OAR-2011-0044** **FRL-9286-1**

JOINT COMMENTS OF THE ELECTRIC RELIABILITY COUNCIL OF TEXAS, THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, THE NEW YORK INDEPENDENT SYSTEM OPERATOR, PJM INTERCONNECTION, L.L.C., AND THE SOUTHWEST POWER POOL

Pursuant to the May 3, 2011 Federal Register notice in the above-referenced proceeding,[1] the Electric Reliability Council of Texas ("ERCOT"), Midwest Independent Transmission System Operator ("MISO"), New York Independent System Operator ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and the Southwest Power Pool ("SPP") (the "Joint RTO Commentors") submit these comments on the Proposed Rule in the above-referenced proceeding. These entities are the designated Regional Transmission Organizations ("RTOs") or Independent System Operators ("ISOs") in their respective footprints, having been so designated by the Federal Energy Regulatory Commission ("FERC") or, in the case of ERCOT, the Public Utility Commission of Texas. RTOs and ISOs are responsible for ensuring the continued reliability of the bulk power system in order to "keep the lights on" to millions of Americans in our respective footprints. Together the Joint RTO Commentors serve over 146 million Americans. The RTOs and ISOs are independent entities with no financial stake in any generator or other market participant.

These Comments specifically focus on the compliance timeframe discussed in Section V.M. of the Proposed Rule. The Joint RTO Commentors are not taking a position on the merits of the Proposed Rule or the merits of requests for a blanket delay in its implementation. Rather, the Joint RTO Commentors are concerned about the impacts of the implementation timeline for the Proposed Rule.[2] Accordingly, the Joint

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[1] U.S. Environmental Protection Agency National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial- Institutional, and Small Industrial- Commercial-Institutional Steam Generating Units, 79 Fed. Reg. 24976 (proposed May 3, 2011) (to be codified at 40 C.F.R. Pts. 60 & 63) ("Proposed Rule").
[2] The Joint RTO Commenters note that retirement decisions are affected not just by the instant Proposed Rule but by the costs of compliance with the suite of EPA rules including the Cross State Air Pollution

Commentors urge that the EPA consider authorizing a targeted backstop reliability safeguard, on a unit-specific basis, to ensure that the compliance deadlines set forth in the Proposed Rule do not cause electric grid reliability issues that cannot be remedied within the proposed compliance deadline.

I. BACKGROUND

A. Description of the Joint RTO Commentors

ERCOT manages the flow of electric power to 23 million Texas customers – representing 85 percent of the state's electric load and 75 percent of the Texas land area. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6.6 million Texans in competitive choice areas.

MISO is the RTO that provides open-access transmission service and monitors the high voltage transmission system throughout the Midwest United States and Manitoba, Canada. MISO operates one of the world's largest real-time energy markets and has 93,600 miles of transmission lines under its direction in a region with an estimated population of 40.3 million.

NYISO is a federally regulated, nonprofit corporation established to facilitate the restructuring of New York's electric industry. NYISO operates a 10,775-mile network of high-voltage lines that carry electricity throughout the state, serving approximately 19.2 million customers, and administers the state's wholesale energy markets. NYISO is responsible for the New York Control Area which is part of the Eastern Interconnection, a vast area of interconnected power systems that cover most of the eastern US and Canada.

PJM serves all or parts of the states of Illinois, Indiana, Michigan, Kentucky, Tennessee, Ohio, West Virginia, North Carolina, Virginia, Maryland, Delaware, Pennsylvania and New Jersey plus the District of Columbia. PJM is responsible for both the planning and reliable operation of the bulk power electric grid serving over 58 million people in its region. PJM manages over 180,000 MW of generation which collectively serves a peak demand of over 158,000 MW.

SPP is based in Little Rock, Arkansas and serves over 6.2 million households, with approximately 15.5 million consumers. SPP provides the following services to members in nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. SPP monitors power flow throughout its footprint and coordinates regional response in emergency situations or blackouts.

Rule, the proposed Clean Water Act section 316(b) cooling water intake rule and the Coal Combustion Residuals Disposal regulation.

B. The Role of RTOs in Ensuring System Reliability

Pursuant to legislative and regulatory directives, the Joint RTO Commentors are charged with ensuring the reliability of the bulk power electric grid in their respective footprints. FERC Order No. 2000[3] and, in the case of ERCOT, Section 39.151(a)(2) of the Public Utility Regulatory Act and Texas PUC Substantive Rule 25.361(b), charge RTOs and ISOs with ensuring the reliable operation of the grid on a daily basis and planning transmission to ensure long term grid reliability. In performing these functions, the ISOs/RTOs must comply with reliability standards promulgated by the North American Electric Reliability Corporation, and, where relevant, applicable state authority. [4]

ISOs/RTOs do not have authority to build generation or to compel existing generation to operate. Rather, the ISO/RTO model is based on a market platform that provides financial incentives designed to facilitate generation adequacy consistent with applicable reliability standards. By contrast, transmission assets are regulated, and as a result, the ISO/RTOs plan for, and have the authority pursuant to their tariffs to direct, the expansion of the transmission grid to address reliability issues.

Under this construct, ISOs/RTOs receive limited notice of a generator unit's intent to retire.[5] Specifically, the rules of the Joint RTO Commentors provide for the following notice periods:

- ERCOT – 90 days notice for units taken out of service for periods that exceed 180 days (ERCOT Protocol Section 3.14.1.1)
- MISO – 26 weeks (MISO Tariff section 38.2.7 and Attachment Y);
- NYISO – 180 days for generators larger than 80 MW and 90 days for generators smaller than 80MW (NYSPC Case No. 05-E-0889);[6]
- PJM – 90 days notice (PJM Tariff section 113.1 and 113.2);
- SPP – 45 days (SPP EIS Protocols Section 12)

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[3] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) ("FERC Order No. 2000").

[4] The Joint RTO Commenters utilize open stakeholder processes as a key feature of their planning processes.

[5] The limited notice requirements reflect the deregulated status of generation, the competitively sensitive nature of generator intentions and the influence of changing projections of future natural gas prices on generator retirement decisions.

[6] *Proceeding on Motion of the Commission to Establish Policies and Procedures Regarding Generation Unit Retirements, Order Adopting Notice Requirements for Generation Unit Retirements* (issued and effective December 20, 2005); *see also* NYISO Technical Bulletin 185, (establishing procedures for generation unit retirements) at http://www.nyiso.com/public/webdocs/documents/tech_bulletins/tb_185.pdf .

Moreover, FERC has indicated that due to the deregulated status of generation, the RTOs do not have authority to simply prohibit units from retiring.[7] Similarly, under the deregulated structure of the ERCOT market, ERCOT does not have the authority to outright prohibit generation retirements.

When an ISO/RTO receives notice of a generation retirement, it assesses the reliability impact. There are numerous factors that affect the retirement reliability assessment. These include, but are not limited to, the operating characteristics of a unit, the number of proposed retirements and the location of the units. Based on this analysis, the ISO/RTO will plan transmission upgrades as necessary to ensure reliability limits are respected.[8] Market response solutions, such as the addition of generation, demand response or energy efficiency resources, could also help mitigate reliability impacts of retiring generation depending upon their location and are considered by the ISO/RTO in its public planning process.

C. The Impact of EPA's Proposed Rule

The Joint RTO Commentors are concerned that EPA's Proposed Rule may accelerate the number of generation retirements as generation asset owners assess the costs of complying with this rule in the context of a host of new environmental imperatives being imposed on them. For several, these new requirements could render their assets uneconomic in the ISO/RTO market environment. Environmental compliance is a cost of doing business in a market environment. However, if the impact of the EPA rulemakings increases retirements to the point of creating reliability violations without providing for adequate time to respond to the reliability concerns, this could undermine the reliability of the electric grid for an unacceptable prolonged period.

Admittedly, it is difficult to assess the full scope of local and regional reliability impacts absent information from each of the asset owners as to their intentions to retrofit or retire their units. Unfortunately, those decisions are not fully known at this point because they will be driven, in part, by the provisions of the final EPA rules, their relationship to other environmental rules and future market conditions such as the projected costs of competing fuels and forms of generation. Even if overall regional or national levels of capacity remain sufficient, local reliability impacts, the extent of which are still unknown, can have a profound effect on ensuring system reliability within specific areas that can serve substantial load, such as urban areas.[9]

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[7] *See PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 137 (2005) (where FERC stated: "we are rejecting the specific language . . . that provides that PJM can "require" generators to continue to operate for an indeterminate period, because PJM has not adequately shown that it has the authority to require generators to operate beyond a reasonable notice period.").

[8] Ideally, market based solutions would resolve any reliability issues. However, to the extent the market does not respond, or cannot respond in a timely fashion, the transmission planning process is designed to ensure system capacity is adequate to maintain system reliability.

[9] The Proposed Rule recognized that local reliability impacts were not analyzed. *See* Proposed Rule at 25055.

Although the impacts cannot be stated with certainty, given the potential reliability issues that could result from the impact of this rule within the context of several EPA rulemakings, the Joint RTO Commentors respectfully request that the EPA consider revisions that provide for an extension process that would, in essence, allow for the continued operation of units – "Reliability Critical Units" -- identified by the ISO/RTO through its retirement analysis as necessary to maintain grid reliability. As described in more detail below, the extension would be tailored to the specific reliability need, and would only be effective until such time the reliability issue is remedied via the most expeditious and efficient means available, whether that is transmission reinforcements and/or through replacement resources.

D. The Scope of Requested Relief

As noted, the Joint RTO Commentors are ***not*** taking a position on the merits of the Proposed Rule itself or the EPA's findings as to the long term health and societal benefits of compliance with the Proposed Rule. Rather, the Joint RTO Commentors proposed remedy is focused on addressing potential reliability impacts resulting from the Proposed Rule which cannot be remedied in time to meet the strict compliance deadlines proposed.

E. The Joint RTO Commentors Proposal for Inclusion of a Reliability Safeguard in the Final Rule

The Joint RTO Commentors also are not asking for a blanket extension of the proposed rule's compliance timeframe. The Proposed Rule provides that existing generators must comply with the final rule no later than 3 years from the effective date of the final rule. A 1-year extension may be granted if pollution control equipment is being installed to achieve compliance.[10] Further, the Proposed Rule would interpret the Clean Air Act such that States can grant the 1-year extension when on-site replacement power is being constructed to replace a retiring generating unit.[11]

Given the potential for reliability impacts due to generation retirements, we ask that the final rule contain a narrowly-drawn reliability "safety valve" such that a retiring generator could be granted an extension for the time needed to implement reliability solutions to replace the subject resource. The Final Rule should define a clear up-front process, such as use of a "pro forma" Consent Decree, to implement this process.[12] Depending on the circumstances, as identified by the ISO/RTO to the EPA, the time period could be for an additional fourth year under the rule or longer if the

[10] Proposed Rule at 25,054.
[11] Proposed Rule at 25,055.
[12] On a unit-specific basis, an agreed date certain would be determined by the RTO/ISO and provided to EPA. The date certain would reflect a realistic estimate as to the time needed for planning and constructing transmission upgrades or securing alternative resources to address the specific reliability challenges being addressed.

circumstances so require. This "safety valve" would be limited to situations where the following conditions are met:

- The asset owner provides notice of retirement to the ISO/RTO within 12 months of the effective date of the rule, or January 1, 2013, whichever is earlier;
- The ISO/RTO, after analysis through its public planning process, identifies the unit as a "Reliability Critical Unit"; and
- The transmission reinforcements and/or replacement resources (generation, demand response and/or targeted energy efficiency) that are being installed to mitigate the reliability impacts are expected to take more than 3 years to be placed into service.[13]

Linking eligibility for the "pro forma" Consent Decree extension to the provision of an accelerated notice of retirement is key to this proposal. This advance retirement notice could provide at least two years' advance notice of retirement, notwithstanding the substantially shorter timeframes that would otherwise apply, as mentioned. The Joint RTO Commentors believe that timely notice to the ISO/RTO (and potentially EPA) of a unit owner's intentions is critical to ensuring that there is a realistic opportunity for the ISO/RTO to plan and direct implementation of transmission upgrades or ensure adequate alternative resources are available to maintain local and regional reliability challenges that might result from the retirement. The process would apply on a case-by case basis and the Joint RTO Commentors anticipate that it would not need to be invoked often, if at all.

The proposed "safety valve" is intended to provide a "safe harbor" for those retiring generators who meet the eligibility criteria – including providing the advanced notice of retirement – as outlined above. It provides for a process which is clear to all affected parties up front. Moreover, the proposed process is a more cost effective and efficient means to address both environmental and reliability goals without having to resort to last minute appeals to the Secretary of Energy to exercise his authority under Section 202(c) of the Federal Power Act[14] and Section 301(b) of the Department of Energy Organization Act[15] to order the unit to remain operational.

The Joint RTO Commentors stand ready to work with the EPA to ensure that this reliability safety valve is available in the narrow circumstances described above. Incorporating such an approach in the Final Rule will enable the EPA to meet Congress'

[13] The above process is presented as a proposal from the Joint RTO Commenters. The individual RTOs pledge to work with the EPA on the specific implementation details of this proposal as applied to their region.
[14] 16 U.S.C. § 824a(c).
[15] 42 U.S.C. § 7151(b)

mandate for environmental compliance embodied in the Clean Air Act while also respecting Congress' mandate to ensure the reliability of the bulk power system as per the provisions of the Energy Policy Act of 2005.

Respectfully submitted:

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July 19,2011 CEO Statement Regarding EPA Cross-State Air Pollution Rule
H.B. "Trip" Doggett
President and Chief Executive Officer
Electric Reliability Council of Texas

As the independent system operator for the Texas electric grid, we fulfill specific responsibilities assigned by the Public Utility Commission of Texas and the Texas Legislature - primarily, responsibility for the reliability of electricity across the state's main interconnected power grid. We are a non-profit organization; we don't own generation or transmission; nor do we advocate for or against policy positions - except in cases where electric grid reliability may be affected. This is one of those cases where we believe it is our role to voice our concern that Texas could face a shortage of generation necessary to keep the lights on in Texas within a few years, if the EPA's Cross-State Rule is implemented as written.

ERCOT's May11 report to the Public Utility Commission on the impact of the proposed environmental regulations did not address the impact of SO2 restrictions on coal plants in ERCOT because these restrictions on Texas were not included as part of the EPA's earlier rule proposal. We have not had time to fully analyze the entire 1,323-page Cross-State Rule released July 7 or to communicate with the generation owners regarding what their intentions will be. However, initial implications are that the SO2 requirements for Texas added at the last stage of the rule development will have a significant impact on coal generation, which provided 40 percent of the electricity consumed in ERCOT in 2010.

Our concern is that the timing of the new requirements - effective Jan. 1, 2012 - is unreasonable because it does not allow enough time to implement operational responses to ensure reliability. We fear that many of the coal plants in ERCOT will be forced to limit or shut down operations in order to maintain compliance with the new rule, possibly leading to inadequate operating reserve margins with insufficient time to reliably retrofit existing generation or build new, replacement generation.

In the state's deregulated electric market, the generation owner bears the risk of investment and decides when and where to build new generation, and whether to retire or mothball existing generation, based on market conditions. ERCOT's role in the competitive market is to provide an outlook for future peak demand and how much generation will be needed to maintain long-term reliability of the electric grid. At this time, it is not clear that ERCOT operations has adequate tools to maintain long-term reliability in the face of the possible loss of a large amount of existing baseload generation in such a short period of time.

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PJM'S COMMENTS TO EPA PROPOSED HAZARDOUS AIR POLLUTANT RULE

The Environmental Protection Agency (EPA) has called for comments to its proposed rule establishing national emission standards for Hazardous Air Pollutants (NESHAP). In its comments filed today, PJM, the regional grid operator serving the Midwest and Mid-Atlantic region, raises concerns as to whether the EPA's analysis adequately captures the potential impact of the EPA rule on the need to ensure reliability of the grid in "load pockets" and other congested parts of the grid. PJM is charged under law with managing the reliability of the high voltage electric grid. PJM operates the high voltage power grid in all or parts of the states of Illinois, Indiana, Michigan, Ohio, Kentucky, Tennessee, West Virginia, North Carolina, Virginia, Maryland, Delaware, Pennsylvania, New Jersey and the District of Columbia, an area which includes 58 million people and represents 20% of the nation's Gross Domestic Product. In addition to its reliability responsibility, PJM is charged with the responsibility of planning for the infrastructure development of the transmission grid and in that role has studied the potential impact of the rule on system reliability.

When generating units are permanently shut down, grid planners such as PJM must find alternative resources (such as new transmission, demand response, or new generation) to reliably maintain electricity supply throughout the system. Although on a regional basis PJM does not expect a generation capacity shortfall, there may be local reliability issues that need to be addressed to ensure system improvements are in place before generation units retire. EPA's analysis did not sufficiently take into account these local reliability impacts.

In its comments, PJM proposes a targeted remedy to address the potential that insufficient time may exist for the deployment of alternative resources in response to the retirement of a plant that is otherwise critical for ensuring local reliability. Specifically, PJM proposes that EPA include in its Final Rule a "reliability safety valve" for specific units deemed "Reliability Critical Units," where an individual unit's shutdown would adversely impact local reliability.

The key points are:

- Generating plants which otherwise would shutdown but are deemed "Reliability Critical Units" by a Regional Transmission Organization (such as PJM) or Reliability Coordinator (in non RTO regions) would be eligible for a compliance extension for that period needed until alternative resources (either new transmission, generation or targeted demand response and energy efficiency programs) are in place to address the reliability issue created by the shutdown.

- Such Reliability Critical Generating Plants would qualify for the "safe harbor extension" (i.e. not face penalties for violation of the EPA rule) if they provide the Regional Transmission Organization with notice of their intended shutdown at least two years before the EPA compliance deadline. Currently, in PJM the rules only require generators to provide 90 days' notice. Advanced notice of plant owner's intention is critical to ensuring that there is adequate time for the development of alternative resources to meet the reliability need resulting from the potential plant shutdown.

The complete set of PJM's comments are posted at www.pjm.com. In addition to its own comments, PJM is joining with similar Regional Transmission Organizations in the Midwest (MISO), the Southeast (SPP), Texas (ERCOT) and New York (NY ISO), as a group in reiterating this need for a reliability safety valve to be incorporated into the Final EPA rule. Those comments are also posted at www.pjm.com.

For more information, contact Craig Glazer, PJM Vice President of Federal Government Policy at 202-423-4743 or by e-mail at glazec@pjm.com.

PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 58 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 61,000 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.

Mr. WHITFIELD. Thank you.

Mr. Shurtleff, you are recognized for 5 minutes.

STATEMENT OF MARK L. SHURTLEFF

Mr. SHURTLEFF. Thank you, Chairman Whitfield, Ranking Member Rush, members of the subcommittee. It is an honor to be here today with you, and my name is Mark Shurtleff. I am the Attorney General for the State of Utah. It is a pleasure to be with all these great experts on this panel. I want to just focus if I may my brief remarks on one rule that is imminent, and that is the Utility MACT which the EPA seems intent on proposing or adopting before November 16th.

As I heard Commissioner Spitzer say in the prior panel, the best time for analysis is before a rule becomes final. Time is running out clearly on this rule. Eighteen Attorneys General including, Mr. Chairman, my friend, the Attorney General of Kentucky, Mr. Conway, have sent letters to the EPA Administrator asking that they withdraw the proposed MACT rule. As the chief legal officers of our States, we are most concerned with the rule of law. The EPA has clearly failed to assess the impact of that rule on a cumulative basis in light of its other promulgated, proposed and pending regulations governing electric power generation, and without the cumulative analysis, neither the EPA, FERC, Congress nor the public can truly understand the effect of all these regulations and the reliability of the electric grid and indeed on the economy, on jobs and electricity rates to consumers.

The law requires cumulative analysis. Under Executive Order 13563 signed by President Obama in January of this year, federal agencies must assess the cumulative impact of their proposed regulations including costs and they must tailor them to impose the least burden on society. The EPA has failed to do so.

A cumulative impact analysis is extremely important from a practical perspective. If it is adopted, the Utility MACT Rule will clearly not operate in isolation. Instead, there are a large number of related regulations that EPA has already adopted or has proposed for adoption and is currently considering. Yet Congressman Waxman and Chairman Wellinghoff had this interaction about whether FERC staff was reliable or unreliable and what they had to rely on in order to make their recommendations. The EPA should do this. They can do it. The private sector has done cumulative analysis and the results are very disturbing.

As just mentioned by Commissioner McKinney, the American Coalition for Clean Coal Electricity, ACCCE, commissioned the highly regarded National Economic Research Association to prepare a report, and they just looked at just two regulations, the Cross-State Air Pollution Rule, which Ranking Member Rush mentioned ought to be something studied, but they looked at that and the Utility MACT Rule and said it would be a serious blow to the economy, as mentioned, a net loss. Now, this takes into consideration—I think Mr. Inslee earlier in the prior panel mentioned jobs created. They said there would be 430,000 jobs created but 1.8 million lost, so the net loss would be 1.4 million jobs by 2020. The combination of those two regulations would also be a substantial increase in costs, in some places as much as 23 percent increase in the cost of electricity prices, could be a total of $184 billion in the next 20 years.

So last week's cascading blackout in the southwestern United States clearly shows what we all know already, and that is, the grid if very interdependent, that these disruptions in one location can have far-reaching consequences. So the EPA should not proceed with the whole suite of regulations designed to restructure the utility industry without that careful and complete analysis as required by law.

Now, the EPA is claiming that it has to move forward with these proposed utility MACT rules under a federal consent decree. Listen, I understand, we have been under federal consent decrees and we can't get out from under them. I get that. But they—and that consent decree says they have to do this by November 16th, 2 months away. However, you need to know that the EPA agreed to that deadline. They proposed that deadline. So I think it is wrong for a federal agency to avoid its legal responsibilities by hiding behind a deadline of its own creation, that consent decree, and you have to understand, the consent decree is not hard and fast, either. They can clearly seek an extension for good cause shown. Clearly, this is a case of good cause for extending the deadline as required by law.

Unfortunately, it seems like they are going to go forward. They will take action with this ill-advised regulation that is proposed, and so I would urge Congress to take whatever action it can. If EPA goes forward on November 16th and adopts the utility MACT, whatever you can do, to enact legislation that would defer that rule and other major power sector regulations at least and until they fulfill their responsibility under the law to perform a cumulative impact analysis. You know, State officials, we protect not only interests of local jobs and the economy and electric reliability but what the law mandates, and we would ask you to hold the EPA to that requirement as well.

Thank you, sir.

[The prepared statement of Mr. Shurtleff follows:]

Testimony of Mark L. Shurtleff,
Attorney General of Utah,
Before the House Committee on Energy and Commerce

The American Energy Initiative: Impacts of the Environmental Protection Agency's New and Proposed Power Sector Regulations on Electric Reliability

September 15, 2011

Thank you for the opportunity to testify here today.

As the Attorney General of the State of Utah, I am deeply concerned about recent actions taken by the Environmental Protection Agency in proposing new regulations to govern the people of my State. Of particular concern to me is the so-called Utility MACT Rule,[1] which the EPA now seems intent on adopting on or before November 16, 2011. Last month, I filed comments with the EPA in objection to that proposed rule. Indeed, eighteen Attorneys General from across the country – both Republicans and Democrats – filed several letters objecting to that proposal.[2]

The substance of my objections was that EPA had failed to assess the impact of the rule – on a cumulative basis – in light of all of its now-promulgated regulations, proposed regulations, and impending regulations governing electric power generation. Without such a cumulative analysis, neither EPA nor the public can understand the effect of all of these regulations on the

1 1 "Maximum Achievable Control Technology Rule."

2 2 The other Attorneys Generals who submitted objections are: Hon. Luther Strange (R – Alabama); Hon. John Burns (R – Alaska); Hon. Dustin McDaniel (D – Arkansas); Hon. Thomas Horne (R – Arizona); Hon. Pam Bondi (R – Florida); Hon. Leonardo Rapadas (I – Guam); Hon. Gregory Zoeller (R – Indiana); Hon. Derek Schmidt (R – Kansas); Hon. Jack Conway (D – Kentucky); Hon. James Caldwell (R – Louisiana); Hon. Bill Schuette (R – Michigan); Hon. Jon Bruning (R – Nebraska); Hon. Wayne Stenehjem (R – North Dakota); Hon. Mike DeWine (R – Ohio); Hon. E. Scott Pruitt (R – Oklahoma); and Hon. Alan Wilson (R – South Carolina); and Hon. Marty Jackley (R – South Dakota)

reliability of the electric grid and, indeed, on the economy, jobs, and electricity rates to consumers.

Failing to cumulatively address the effect of such wide-sweeping regulatory activity is not only bad public policy, it is fundamentally at odds with the law. The President of the United States has given federal agencies clear directions about the procedures they must follow when they propose new regulations. Under an Executive Order issued by President Obama in January 2011 – Executive Order No. 13,563 – it is not enough for federal agencies to assess the effect of their regulations piecemeal. Instead, the Executive Order requires federal agencies to assess the *cumulative* impact of their proposed regulations.[3] In proposing the Utility MACT Rule, the EPA violated this Executive Order because it did not perform any cumulative impact assessment. It was for this reason that I, along with several other Attorneys General – of both parties – called on the EPA to withdraw its proposed Utility MACT Rule, at least until such time as that agency conducts a cumulative impact analysis, as directed by the President.

The legal analysis that supports our position is set forth – chapter and verse – in the letter that we submitted to the EPA and that is attached to my written testimony filed with the Committee. Rather than repeat all those details here, let me point out that President Obama's Executive Order on this point was not entirely new. Instead, it supplemented and reaffirmed a previous Executive Order issued by President Bill Clinton in 1993.

What President Clinton said – and what President Obama reaffirmed – is this:

> Each agency shall tailor its regulations to ***impose the least burden on society***, including individuals, businesses of differing sizes, and other entities (including small communities and governmental entities), consistent with obtaining

[3] *See* 76 Fed. Reg. 3, 821 (Jan. 18, 2011).

> regulatory objectives, taking into account, among other things, and to the extent practicable, ***the costs of cumulative regulations.***[4]

This requirement to take into account the cost of cumulative regulations goes back at least as far as President Ronald Reagan, whose own Executive Order required federal agencies, when they propose new regulations, to "tak[e] into account the condition of the particular industries affected by regulations . . . *and other regulatory actions contemplated for the future.*") (Executive Order No. 12,291, in 1981.)[5]

When President Reagan, President Clinton and President Obama all agree on how federal agencies need to conduct themselves – and spanning what is now three decades – you would think that EPA would get the message and act accordingly. Unfortunately, EPA did not get the message. It proposed the Utility MACT Rule without performing a cumulative impact analysis. It has not used cumulative analysis to inform any of its other power sector rulemaking activity. And that is simply wrong.

Now let me be clear: I did not file comments with the EPA, and I did not come to Washington today, to complain about a mere technicality. Performing a cumulative impact analysis is extremely important from a practical perspective. If it is adopted, the Utility MACT Rule will not operate in isolation. Instead, there are a large number of related regulations that EPA has already adopted, proposed for adoption, or is currently considering proposing.[6]

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[4] [4] Executive Order No. 12,866, 58 Fed. Reg. 51,735, 51,736 (Sept. 30, 1993) (emphasis added).

[5] [5] *See* 46 Fed. Reg. 13,193 (Feb. 19, 1981) (emphasis added).

[6] [6] These regulations include: (a) EPA's now final regulations for "PSD" and "Title V" permitting for greenhouse gas emissions, the SO2 and NO2 NAAQS, and the Cross-State Air Pollution Rule, (b) the currently proposed Utility MACT Rule, coal ash rule and "316(b)" water intake structure rule, and (c) the impending rules for greenhouse gas new source performance standards for electric generators, new particulate matter NAAQS, and new ozone NAAQS (which, although delayed, are still on EPA's agenda).

EPA should have conducted an analysis of how society will be impacted by the Utility MACT Rule, acting together with these other rules. Although the EPA has failed to do so, the private sector has done so – and the results are very disturbing.

The American Coalition for Clean Coal Electricity ("ACCE"), commissioned the highly-regarded National Economic Research Associates ("NERA") to prepare a report. The initial NERA report shows that the combination of just two of these regulations, the Cross-State Air Pollution Rule and the Utility MACT Rule, will be a serious blow to the economy, causing a net loss of 1.4 million jobs by 2020![7] The combination of the two regulations will also cause a substantial increase in retail electricity prices, with the price increase estimated to top 23 percent in some areas of the country. Even for states where the projected increase may be small, we are – at the end of the day – one nation, and we prosper most when we all prosper together. These electricity price increases will cause direct harm in the states were they occur; but they will also cause indirect harm in other states as well.

I must emphasize that EPA has no credible basis for stating that these harms will not occur because, unlike the private sector, that agency has not conducted a cumulative impact analysis – even though the President's Executive Order requires it.

The issue is not just the cost of electricity and the impact these costs will have on jobs and the economy. The reliability of the electric grid may be at stake as well. The events of last week illustrate why I am so concerned about this issue. What evidently was a mistake by a single utility worker at a facility in Yuma, Arizona, triggered a cascading effect that ended up blacking out almost 5 million people from Mexico to Orange County, California. According to press reports, during the outage, schools and businesses – including gas stations – were forced to

[7] [7] The report can be found at http://www.americaspower.org /NERA_CATR_MACT_29.pdf.

close; commuters jammed roadways; the medically-fragile packed hospitals; and at least two sewage pumps failed; and that failure, in turn, contaminated a lagoon and a river that feeds into San Diego Bay. These events show that our electric grid is not only very interdependent, but that disruptions in one location can have far-reaching consequences. In light of these events, one would hope and expect that our nation's regulators would not proceed with a suite of regulations designed to restructure the utility industry without careful and complete analysis. Yet that has not happened with EPA's regulations.

In criticizing the EPA, I am aware that the agency is operating under a consent decree in the case of *American Nurses Association v. Jackson*. In that case, the EPA agreed to adopt a final rule for coal-fired and oil-fired electric generating units by November 16, 2011 – now just two months away.[8] Perhaps, that looming deadline is the excuse it will use to explain its failure to conduct a cumulative impact analysis as the Executive Order requires. But the EPA did not have to agree to that deadline; and it is simply wrong for a federal agency to avoid its legal responsibilities by hiding behind a deadline of its own creation.

In any event, the deadline is not hard and fast. The same consent decree allows the EPA to go back to the court and seek an extension of time "for good cause shown." Certainly, there is "good cause" for extending the court-supervised deadline when the agency has yet to consider the cumulative impact of the Utility MACT Rule in combination with the other rules it has already adopted and/or is now developing.

Hopefully, the EPA will seek such an extension. However, it is very unlikely that the EPA will take any action that would in any way slow down the ill-advised regulation that it has

[8] [8] *American Nurses Assoc. v. Jackson*, No. 1:08-02198 (D.D.C.) (consent decree dated April, 2010).

proposed. And so, the matter now becomes an appropriate subject of *Congressional* action. I urge Congress to propose and enact legislation that defers the Utility MACT Rule and EPA's other major power sector regulations, at least until a cumulative impact analysis can be performed.

STATE ATTORNEYS GENERAL
A Communication from the Chief Legal Officer of the States of
Arizona, Florida, Guam, Indiana, Kansas, Kentucky, Ohio, Oklahoma and Utah.

August 4, 2011

Hon. Lisa P. Jackson
Administrator
U.S. Environmental Protection Agency
EPA Headquarters – Ariel Ross Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, D.C. 20460

Re: Proposed Utility MACT Rule:
EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044

Dear Ms. Jackson:

As State Attorneys General, we are writing because of our concern about the lawfulness of the procedures followed by the Environmental Protection Agency ("EPA") in developing its recently proposed regulation, "Maximum Achievable Control Technology Rule" for utilities ("Utility MACT Rule").

In our view, the EPA has not abided by the direction given to federal agencies – including the EPA – by President Barrack Obama with respect to the procedures that agencies must follow to assess the *cumulative* impact of their proposed regulations. *See* Executive Order No. 13,563, 76 Fed. Reg. 3, 821 (Jan. 18, 2011). Given this lack of compliance, we ask that your agency withdraw its proposed Utility MACT Rule, at least until such time as your agency conducts a cumulative impact analysis, as directed by the President.

President Obama issued Executive Order No. 13,563 in order to make it clear that federal agencies are to assess the cost of cumulative regulations when they propose to impose new requirements on society, including businesses. His Executive Order "is supplemental to and reaffirms the principles, structures, and definitions governing contemporary regulatory review that were established in Executive Order 12,866 of September 30, 1993."[1] Thus, in order to ascertain the full effect of Executive Order No. 13,563, it is necessary to turn to the previous Executive Order, cited by President Obama, on this subject.

Issued by President Bill Clinton, Executive Order 12,866 provides:

[1] Executive Order No. 13,563, 76 Fed. Reg. 3,821 (Jan. 18, 2011).

> Each agency shall tailor its regulations to impose the least burden on society, including individuals, businesses of differing sizes, and other entities (including small communities and governmental entities), consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, *the costs of cumulative regulations.*[2]

This focus on a cumulative analysis reflects the view that government regulations should be examined for their overall effect, and not simply looked at in isolation. As Executive Order No. 12,866 explains, "[i]n deciding whether and how to regulate, agencies should assess *all* costs and benefits of available regulatory alternatives."[3]

In evaluating the proposed Utility MACT Rule, a cumulative impact analysis is especially important because of the large number of related regulations the EPA has adopted, has proposed for adoption, and/or is currently considering proposing. Although EPA has not conducted its own cumulative analysis, the private sector has done so, focusing on the combined impact of the proposed Utility MACT Rule and the recently-adopted Transport Rule (a/k/a Cross-State Air Pollution Rule).

As you may know from the comments filed in opposition to the Utility MACT Rule, the American Coalition for Clean Coal Electricity ("ACCE"), commissioned the highly-regarded National Economic Research Associates ("NERA") to prepare a report. The initial NERA report shows that the combination of the Transport Rule and the Utility MACT Rule will be a serious blow to the economy, causing a net loss of 1.4 million jobs by 2020.[4] The combination of the two regulations will also cause a substantial increase in retail electricity prices, with the price increase estimated to top 23 percent in some areas of the country.

In our judgment, it would be arbitrary and capricious for your agency to adopt the proposed Utility MACT Rule without conducting a cumulative impact analysis. Even without Executive Orders No. 13,563 and 12,866, the dire results of the privately-commissioned NERA analysis would make it irresponsible for your agency to do so. Given President Obama's directive – as set forth in those Executive Orders – we believe that it is especially inappropriate for your agency to proceed on its current course.

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2 Executive Order No. 12,866, 58 Fed. Reg. 51,735, 51,736 (Sept. 30, 1993) (emphasis added). It should also be noted that the requirement for a cumulative impact analysis dates back to President Ronald Reagan, who required federal agencies, when they propose new regulations to "tak[e] into account the condition of the particular industries affected by regulations . . . *and other regulatory actions contemplated for the future.*") (emphasis added). *See* Executive Order No. 12,291, 46 Fed. Reg. 13,193 (Feb. 19, 1981).

3 *Id.* (emphasis added).

4 The report can be found at http://www.americaspower.org /NERA_CATR_MACT_29.pdf.

We ask that the proposed Utility MACT Rule be withdrawn until full compliance with those Executive Orders is achieved.

In making this request, we recognize that you have agreed to a consent decree that gives you a November 16, 2011 deadline for adopting a final rule governing coal- and oil-fired electric generating units.[5] We also recognize, however, that the deadline is not set in stone, and that you are able to ask the court to extend the deadline "for good cause shown." The need for your agency to conduct a cumulative analysis – as required by Executive Orders No. 13,563 and 12,866 – would certainly constitute good cause, and we would be pleased to support the need for an extended deadline if you ask the court to grant it.

Sincerely,

Tom Horne

Thomas Horne
Attorney General of Arizona

Pam Bondi
Attorney General of Florida

Jack Conway
Attorney General of Kentucky

Leonardo M. Rapadas
Attorney General of Guam

Mike DeWine

Mike DeWine
Attorney General of Ohio

Gregory F. Zoeller
Attorney General of Indiana

E. Scott Pruitt
Attorney General of Oklahoma

Derek Schmidt

Derek Schmidt
Attorney General of Kansas

Mark L. Shurtleff
Attorney General of Utah

5 *See American Nurses Assoc. v. Jackson*, No. 1:08-02198 (D.D.C.).

Summary of Testimony of Mark L. Shurtleff, Attorney General of Utah,
Before the House Committee on Energy and Commerce – September 15, 2011

EPA is likely to adopt the Utility MACT Rule by November 16, 2011. But, EPA has failed to assess the impact of the rule on a cumulative basis – in light of other promulgated and proposed regulations. Thus, neither EPA nor the public can understand the effect of all of these regulations on the reliability of the electric grid, or on the economy, jobs, and electricity rates.

The law requires a cumulative analysis. Under Executive Order 13,563, issued in January 2011, federal agencies must assess the cumulative impact of proposed regulations. EPA failed to do so. A cumulative impact analysis is also important from a practical perspective. If adopted, the Utility MACT Rule will not operate in isolation. There are many related regulations that EPA has already adopted or has proposed or is currently considering proposing.

The private sector has conducted a cumulative analysis, and the results are very disturbing. A report prepared by the National Economic Research Associates ("NERA") shows that the combination of just two regulations, the Cross-State Air Pollution Rule and the Utility MACT Rule, will cause (a) a net loss of 1.4 million jobs by 2020, and (b) a substantial increase in retail electricity prices, with the increase estimated to top 23 percent in some areas.

Moreover, reliability of the electric grid is an issue. Last week's cascading blackout in the Southwest shows that our electric grid is very interdependent and that disruptions in one location can have far-reaching consequences. EPA should not proceed with a suite of regulations designed to restructure the utility industry without careful and complete analysis.

The EPA is under a consent decree to adopt a final rule for coal-fired and oil-fired electric generating units by November 16, 2011. But the EPA did not have to agree to that deadline; and it is simply wrong for an agency to avoid its legal responsibilities by using a deadline of its own creation. Moreover, the deadline is not hard and fast. The consent decree allows the EPA to seek an extension "for good cause shown." There is "good cause" for an extension when the agency has yet to consider the cumulative impact of the Utility MACT Rule.

Unfortunately, it seems unlikely that the EPA will take any action that would slow down the ill-advised regulation that it has proposed. I urge Congress to propose and enact legislation that defers the Utility MACT Rule and EPA's other major power sector regulations, at least until a cumulative impact analysis can be performed.

Mr. WHITFIELD. Thank you.

Mr. Doggett, you are recognized for 5 minutes.

STATEMENT OF H.B. DOGGETT

Mr. DOGGETT. Good morning, Chairman Whitfield, Ranking Member Rush and members of the subcommittee. I am Trip Doggett, the CEO of the Electric Reliability Council of Texas. I have a brief footprint above you on the slip of the ERCOT territory. We are the independent system operator that manages the flow of electric power to around 23 million Texans representing about 85 percent of our electric load in the State and 75 percent of the land area. You have asked me to come before the subcommittee today to discuss our report on the impacts of the Cross-State Air Pollution Rule on the ERCOT system.

I will start by saying that I am not here to take a position on the merits of the rule. I am here to express my reliability concerns with the implementation timeline of the rule. As Mr. Terry mentioned earlier, in the proposed Clean Air Transport Rule, Texas was only included in the peak season NOx program and in the final rule, which is now known as the Cross-State Air Pollution Rule, which I will refer to as CSAPR, Texas is included in the annual SO2 and annual NOx programs as well as the peak season NOx program, and in Texas, the annual SO2 limits appear to be the most restrictive.

In July, our Public Utility Commission of Texas asked us to review the impacts of the final rule, and I will highlight the rules effective on January 1, 2012, so our analysis was focused on the near-term reliability implications. We consulted with the owners of our coal-fired generating resources to determine their plans for rule compliance. The individual resource owner compliance strategies were reviewed and aggregated to determine the implications for overall ERCOT system reliability. It is important to note that our analysis did not include a calculation of the cost for compliance for resource owners or the impact on electricity market prices.

Based on the information provided by the resource owners, we developed three possible scenarios of impacts. In what I will refer to as kind of the best case, our first scenario models successful implementation of their compliance plans. In this scenario, the incremental capacity reductions due to CSAPR are expected to be approximately 3,000 megawatts in the off-peak months and approximately 1,200 to 1,400 megawatts in the peak months. You heard earlier today that Luminant announced this week that they would shut down 1,200 megawatts of their generation to comply with the rule, and that 1,200 megawatts was included in our analysis that reflects 1,200 to 1,400 in the peak months. What happens is, capacity reductions in the off-peak months are expected to occur so that they can save their allowances until the peak months. We have a healthy reserve margin within Texas. However, I will highlight that with our reserve margin of over 17 percent, during this past month of August, if ERCOT had experienced the incremental reductions in available generation that we expect to occur from CSAPR, customers in our region would have experienced rotating outages during the month of August.

We also examined two other risks in scenario two. We recognized daily dispatching of units that were designed for baseline would increase potentially that impact to 5,000 megawatts in off-peak, scenario three, up to 6,000 in the off-peak months. Scenario three is related to the availability of low-sulfur coal.

I will summarize by saying when the final CSAPR rule was announced in July, it included Texas in some compliance programs that ERCOT and our resource owners had reasonably believed would not apply to Texas. In addition, the implementation timeline by January 2012 does not provide ERCOT or our resource owners enough time to analyze the impacts. If the implementation deadline for CSAPR were significantly delayed, it would expand our options for maintaining system reliability. I think you have heard consistently from the FERC commissioners that this is not a one-size-fits-all issue of reliability and certainly within Texas we do have reliability issues with the implementation timeline.

Thank you for inviting me.

[The prepared statement of Mr. Doggett follows:]

TESTIMONY OF
H. B. (Trip) Doggett
Electric Reliability Council of Texas, Inc.

BEFORE THE
HOUSE COMMITTEE ON ENERGY AND COMMERCE
SUBCOMMITTEE ON ENERGY AND POWER
UNITED STATES HOUSE OF REPRESENTATIVES

"Impacts of the Cross-State Air Pollution Rule on the ERCOT System"

September 14, 2011

Good morning, Chairman Whitfield, Ranking Member Rush and members of the Subcommittee on Energy and Power. My name is Trip Doggett and I am CEO of the Electric Reliability Council of Texas. ERCOT manages the flow of electric power to 23 million Texas customers --representing 85% of the electric load in the state and 75% of the land area. You have asked me to come before the Subcommittee today to discuss our report on the impacts of the Cross-State Air Pollution Rule (CSAPR) on the ERCOT system. Thank you for the opportunity to testify here today.

Summary

In July, ERCOT was asked by the Public Utility Commission of Texas (PUCT), to evaluate the impacts of the CSAPR on the reliability of the ERCOT grid. The ERCOT analysis included meetings with representatives of the Texas Commission on Environmental Quality and the U.S. Environmental Protection Agency, review of the compliance strategies provided by the owners of coal-fired resources in the ERCOT region, and consolidation of these compliance strategies for purposes of evaluating system-wide impacts.

Based on the information provided by the resource owners, ERCOT developed three scenarios of potential impacts from CSAPR. The first scenario, derived directly from the compliance plans of individual resource owners, indicates that ERCOT will experience a generation capacity reduction of approximately 3,000 MW during the off-peak months of March, April, October and November, and 1,200 – 1,400 MW during the other months of the year, including the peak load months of June, July and August. Scenario 2, which incorporates the potential for increased unit maintenance outages due to repeated daily dispatch of traditionally base-load coal units, results in a generation capacity reduction of approximately 3,000 MW during the off-peak months of March and April; 1,200 – 1,400 MW during the remainder of the first nine months of the year; and approximately 5,000 MW during the fall months of October, November and possibly into December. Scenario 3 includes the impacts noted for Scenario 2, along with potential impacts from limited availability of imported low-sulfur coal. This scenario results in a generation capacity reduction of approximately 3,000 MW during the off-peak months of March and April; 1,200 – 1,400 MW during the remainder of the first nine months of the year; and approximately 6,000 MW during the fall months of October, November and possibly into December.

When the CSAPR rule was announced in July, it included Texas in compliance programs that ERCOT and its resource owners had reasonably believed would not be applied to Texas. In addition, the rule required implementation within five months – by January 2012. The implementation timeline provides ERCOT an extremely truncated period in which to assess the reliability impacts of the rule, and no realistic opportunity to take steps that could even partially mitigate the substantial losses of available operating capacity described in the scenarios examined in this report. In short, the CSAPR implementation date does not provide ERCOT and its resource owners a meaningful window for taking steps to avoid the loss of thousands of megawatts of capacity, and the attendant risks of outages for Texas power users.

If the implementation deadline for CSAPR were significantly delayed, it would expand options for maintaining system reliability. ERCOT is advancing changes in market rules – such as increasing ERCOT's ability to control the number and timing of unit outages and expanding demand response – that could help avert emergency conditions. These measures will not, however, avoid the losses in capacity due to CSAPR that increase the risk of such emergencies. As discussed in this report, those losses will, at best, present significant operating challenges for ERCOT, both in meeting ever-increasing peak demand and in managing off-peak periods in 2012 and beyond.

Introduction

ERCOT was asked by the Public Utility Commission of Texas (PUCT) in the Open Meeting on July 8, 2011, to evaluate the impacts of the Cross-State Air Pollution Rule (CSAPR) on the reliability of the ERCOT grid. The final language of the CSAPR was released by the U.S. Environmental Protection Agency (EPA) on July 6, 2011, and was published in the Federal Register on August 8, 2011.

The CSAPR is one of several environmental rules proposed by EPA that affect electric generation. The CSAPR includes three separate compliance programs: an annual SO_2 program, an annual NO_X program, and a peak season NO_X program (for emissions during the peak ozone season of May – September). In the proposed rule (then known as the Clean Air Transport Rule [CATR]), Texas was only included in the peak season NO_X program. Based on the proposed rule, an ERCOT study completed on June 21, 2011, evaluating the expected impacts of the pending regulations, did not include any incremental impacts from the CATR on the ERCOT system.

In the CSAPR rule actually adopted by the EPA, however, Texas is included in all three compliance programs - the peak season NO_X program, the annual NO_X program, and the annual SO_2 program. The implementation date for the CSAPR is January 1, 2012.

In order to accomplish this review, ERCOT undertook several activities.

- ERCOT reviewed documentation published on the EPA web-site regarding the rule.
- ERCOT met with representatives of the Texas Commission on Environmental Quality (TCEQ) and the EPA.
- ERCOT consulted with environmental experts from several of the generating entities in the ERCOT region whose facilities were likely to be affected by the CSAPR regulations. The purpose of these meetings was to ascertain the likely compliance plans for those resources owners.
- These compliance plans were aggregated so that ERCOT could evaluate the likely impacts to grid reliability.

Rule Description

The CSAPR is being implemented in order to address the interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The rule is a replacement for the Clean Air Interstate Rule (CAIR), which was implemented in 2005. The CAIR was remanded to the EPA by the United States Court of Appeals for the District of Columbia Circuit in 2008. In the CAIR program, Texas was regulated for particulate matter emissions (annual NO_X and SO_2 emissions).

Under CSAPR, generating units in Texas will be regulated for annual emission of SO_2 and NO_X, as well as emissions of NO_X during the peak season (May – September). Each unit will be given a set allocation of emissions allowances. At the end of the calendar year, resource owners must turn in one allowance for each ton of emissions or be subject to penalties. Intra-state trading of allowances between resource owners is unlimited in the rule. However, interstate trading of allowances is capped – no state can have annual net imports of allowances of more than approximately 18% of the total state allocation of allowances. If this limit is exceeded, any resource owner that contributed to the excessive use of imported allowances will be subject to penalties.

Resource owners in Texas are permitted to trade SO_2 allowances with resource owners in Kansas, Nebraska, Minnesota, Alabama, Georgia and South Carolina. Trading of NO_X emissions will be allowed with states as depicted on the following map.

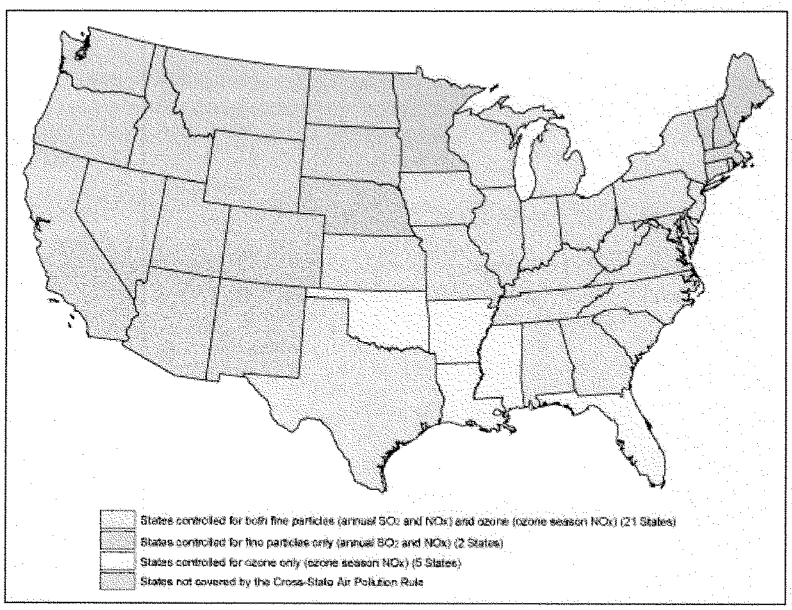

Figure 1: States Included in the Cross-State Air Pollution Rule

Resource owners who have emissions in excess of their annual allocations will have their next year's allocations reduced by one allowance for each excess ton of emissions, plus a penalty of two additional allowances for each excess ton. In addition, the Clean Air Act includes provisions for civil lawsuits in the event of non-compliance. Non-compliance penalties under the CSAPR program are substantial, and can reach up to $37,500 per violation per day. In addition to program penalties, failure to comply can subject entities to the risk of civil penalties, lawsuits by private parties, and criminal liability.

Compliance Options

Resource owners have several near-term compliance options to meet the emissions limits established by the CSAPR. In order to reduce SO_2 emissions, lower sulfur content fuel can be used. In the case of plants that are currently burning lignite coal, or a mix of lignite and sub-bituminous coals (such as coal from the Powder River Basin [PRB] region of northwest Wyoming), increasing the use of low sulfur western coal will reduce SO_2 emissions. Units that currently are being fueled exclusively by western sub-bituminous coals can be switched in whole or in part to ultra-low-sulfur western coals.

In the near-term, the demand for lower sulfur coal is expected to exceed the mining capacity and/or the railroad capacity necessary to deliver the coal to Texas. In addition, the use of lower sulfur coals can result in unit capacity derates due to increased heat content of the fuel. Unit modifications to resolve any such derates may require modifications to the unit's air emissions permit.

Existing SO_2 control equipment, such as wet-limestone scrubbers, can be utilized more frequently than is current practice, and in some cases the effectiveness of this equipment can be increased. This option only applies to a small subset of coal plants in ERCOT, and the use of scrubbers results in a decrease in maximum net output from the affected units of about 1 to 2 percent.

The use of dry sorbent injection is another compliance option to reduce SO_2 emissions. Dry sorbent compounds, such as sodium bicarbonate and trona, can be injected into a flue duct where they react with SO_2 (and acid gases) to form compounds that can be removed using an electrostatic precipitator (ESP) or baghouse. Resource owners exploring this option anticipate that it will provide a 25 – 30% reduction in emissions of SO_2 on units without existing SO_2 control equipment. The use of dry sorbent injection may require public notice or air permit modification.

Most of the low cost options to reduce NO_X emissions have been utilized to comply with existing air quality regulations. Further reductions will likely require high capital cost unit retrofits, including the addition of selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) technologies. Any such unit changes would require several years for permitting, design and construction.

The remaining option for reducing SO_2 and NO_X emissions will be reducing unit output, either through dispatching units down to minimum levels during the off-peak hours and up to maximum capacity during peak afternoon hours, or through extended unit outages. Some of the traditionally base-loaded units will experience increased maintenance outages due to this daily dispatch pattern. These same base-load units have long start-up requirements, which could make them unavailable for operation during some off-peak extreme weather events.

Study Methodology

In order to evaluate the potential impacts associated with implementation of the CSAPR, ERCOT met with representatives of the TCEQ and the EPA to evaluate details of the rule and its implementation. ERCOT also reviewed compliance strategies provided by the owners of coal-fired resources in the ERCOT region. ERCOT consolidated these compliance strategies for purposes of evaluating system-wide impacts.

CSAPR Impacts

The compliance strategies of individual resource owners were compiled and consolidated to determine the aggregate impacts on the ERCOT system. This analysis indicates that, of the three CSAPR programs, the annual SO_2 program is likely to be the most restrictive on the ERCOT system. Even though individual units may have emissions in excess of the peak season or annual NO_X limits, Texas as a whole is likely to be below the state-wide limit, indicating that resource owners can achieve compliance through trading of NO_X emissions allowances. An extended hot summer, such as the one experienced in 2011, may result in limited availability of peak season NO_X emissions, and a need to obtain additional allowances from out-of-state.

In consolidating the compliance strategies from the resource owners, it became apparent that each resource owner was assuming a level of effectiveness of the various compliance options identified. While many of these compliance plans are likely to be adequate, given the risks associated with each compliance option, it is unlikely that all of the resource owners' plans will function as designed. For example, the use of dry sorbent injection on the scale required to attain compliance at certain facilities may perform as anticipated, but its use in this context is novel and may involve unexpected complications. As a result, ERCOT has developed three compliance scenarios in order to assess the potential risks to the system based on different assumptions regarding implementation of compliance strategies.

The first scenario is derived directly from the compliance plans of individual resource owners. Based on the information that ERCOT has been given, in this scenario, the ERCOT region will experience an incremental reduction in available operating capacity of approximately 3,000 MW in the off-peak months of March, April, October and November, and an operating capacity reduction of 1,200 – 1,400 MW during the other months of the year, including the peak load months of June, July and August. Capacity reductions in the off-peak months are expected to be greater because power prices are lower during these periods, making them a more attractive time for resource owners to take extended outages to conserve allocated allowances.

The second scenario is derived from the first, but includes the additional assumption that the increased dispatching of base-load units will lead to increased maintenance outages, especially in the fall months. Over the course of the spring months it may become increasingly apparent that dispatching specific units is leading to extensive maintenance requirements. In these cases it may be cost-effective to idle these units rather than dispatch them down to minimum levels during off-peak hours. These units would likely be run through the summer peak months, but then would be idled for an extended period in the fall in order to conserve allocated allowances. Given this additional constraint, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 5,000 MW of capacity during the fall months of October, November and possibly into December.

The third scenario is derived from the second, with the added consideration of possible near-term market limitations on the availability of imported low-sulfur coals, either due to nationwide demand exceeding mine output capacity or railroad shipping capacity. In the event of such limitations, coal plant resource owners would be forced to rely on higher sulfur coals during the spring and the peak season summer months. As a result, they would be forced to further reduce unit output in the fall months, beyond what is currently included in their compliance strategy, and could be required to decommit additional capacity in October and November in order to conserve allocated allowances. As a result, given these assumptions, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 6,000 MW of capacity during the fall months of October, November and possibly into December.

Discussion

The scenarios analyzed in this study represent best-case (Scenario 1), and two cases with increasing impacts to system reliability. Scenarios 2 and 3 are based on the occurrence of events that are reasonably foreseeable given the circumstances facing generation resources attempting to comply with the CSAPR. Even in the best-case scenario, ERCOT is expected to experience a reduction in available operating capacity of 1,200 – 1,400 MW during the peak season of 2012 due to implementation of the CSAPR. Had this incremental reduction been in place in 2011, ERCOT would have experienced rotating outages during days in August. Off-peak capacity reductions in the three scenarios evaluated as part of this study, when coupled with the annual maintenance outages that must be taken on other generating units and typical weather variability during these periods, also place ERCOT at increasing risk of emergency events, including rotating outages of customer load.

There are numerous unresolved questions associated with the impacts of the CSAPR on the ERCOT system. It is important to note that the resource owners have had less than two months to develop compliance plans for the new rule. These plans are still preliminary and based on assumptions regarding technology effectiveness, fuel markets, impacts of altered unit operations on maintenance requirements, and the cost-effectiveness of modifying and operating units to comply with the CSPAR. The overall system impacts noted in this study will change if these individual compliance strategies are adjusted to take into account updated information.

The availability of SO_2 allowances for purchase by resource owners in Texas is a significant source of uncertainty at this time. A lack of allowances for purchase from out-of-state resources will likely increase the severity of the CSAPR rule. Many resource owners expressed their concern that parties that have excess allowances may, at least initially, hold on to their excess, in order to maintain flexibility and future compliance options. Given the penalties for non-compliance, resource owners are unlikely to exceed the number of allowances they have in hand, with the expectation that allowance markets will open up later in the year. It may be that some resource owners will keep their excess allowances until it becomes clear that they will not be needed, late in the year. Other resource owners may have to shut units down in the early fall in order to conserve allowances.

In addition, the information ERCOT has received indicates there will not be a liquid market throughout the year for allowances, which will make it difficult to determine the appropriate value of allowances to compensate resource owners for operations associated with reliability commitments, such as through the daily or hourly reliability unit commitment process. It may be necessary to administratively establish a value for these allowances through the market stakeholder review process.

It is also possible that the impacts of CSAPR will increase in 2013 and 2014. In those years, it is unlikely that resource owners will have any additional options for rule compliance. Increased dispatching of base-load units will likely continue to lead to extended maintenance outages, and delivered availability of low sulfur western coals is likely to remain limited. In addition to these factors, some resource owners will be placing units on extended outages to install emission control technologies, such as wet-limestone scrubbers and possibly selective catalytic or selective non-catalytic reduction equipment. These retrofit outages could further reduce the generation capacity available during off-peak months.

Due to the numerous uncertainties, ERCOT cannot confidently estimate a "worst case" scenario at this time. Combinations of particular events may result in reductions in operating capacity that exceed those identified in Scenario 3, and thus further increase the risk of increasingly frequent and unpredictable emergency conditions, including the potential for rotating outages. The best outcome ERCOT can expect occurs if Scenario 1 is realized (*i.e.,* all generation resources' current plans come to fruition), and, as discussed above, Scenario 1 appreciably increases risks for the ERCOT system, in both the on-peak and off-peak months.

Conclusion

When the CSAPR rule was announced in July, it included Texas in compliance programs that ERCOT and its resource owners had reasonably believed would not be applied to Texas. In addition, the rule required implementation within five months – by January 2012. The implementation timeline provides ERCOT an extremely truncated period in which to assess the reliability impacts of the rule, and no realistic opportunity to take steps that could even partially mitigate the substantial losses of available operating capacity described in the scenarios examined in this report. In short, the CSAPR implementation date does not provide ERCOT and its resource owners a meaningful window for taking steps to avoid the loss of thousands of megawatts of capacity, and the attendant risks of outages for Texas power users.

If the implementation deadline for CSAPR were significantly delayed, it would expand options for maintaining system reliability. ERCOT is advancing changes in market rules – such as increasing ERCOT's ability to control the number and timing of unit outages and expanding demand response – that could help avert emergency conditions. These measures will not, however, avoid the losses in capacity due to CSAPR that increase the risk of such emergencies. As discussed in this report, those losses will, at best, present significant operating challenges for ERCOT, both in meeting ever-increasing peak demand and in managing off-peak periods in 2012 and beyond.

Mr. WHITFIELD. Thank you.

Ms. Tierney, you are recognized for 5 minutes.

STATEMENT OF SUSAN F. TIERNEY

Ms. TIERNEY. Good afternoon, Mr. Chairman, Ranking Member Rush and members of the subcommittee. I very much appreciate the invitation to testify today on this issue.

I want to focus my testimony on issues relating to the recent air regulations being proposed by the EPA for two reasons, and that is principally because those are the regulations with the most immediate impact on the power sector. I want to focus on two questions: can the Nation get the benefits of both public health and reliable electric supply, and will there be jobs and positive economic activity that flow from the issuance of these rules and their implementation by the industry.

I believe the answer to both of those questions is yes and that the rules can proceed to implementation without a concern that in the end there will be reliability issues, and I am going to give you several reasons why. These are facts and conditions in the marketplace that give me confidence that we are in a manageable situation with regard to these rules.

Number one, the electric industry has a very proven track record of addressing reliable power supplies and doing what it takes at the end of the day to make sure that the lights stay on. These are a group of people with a very strong mission orientation. Every person on my right fits that category as do all of the people in this industry, and they have ensured that we have reliable electricity supply as a priority.

Number two, the new air rules are not a surprise. These are not coming at us in the last few months. These have been underway for over a decade of notice and they allow for more technology options and approaches than originally expected in prior versions of these rules. EPA's rules are technically and economically feasible.

Number three, the owners of a portion, a substantial portion of affected plants, have already taken steps to modernize their facilities so that the companies are ready to comply with the new air regulations. As we heard previously today, many States have already had mercury rules that are tighter than what EPA is proposing. Many companies with facilities affected are under court order to address the issues that are coming forward. In fact, some of the recent announcements we have heard in the industry are coming from violations of current rules and not future rules of the EPA. And finally, we see that the CEOs owning a substantial portion of the power plants affected by these rules have indicated to securities analysts under the Sarbanes-Oxley requirements that they are ready to comply with these regulations.

Number four, current fuel market conditions are already putting economic pressure on the least efficient coal plants. Since 2006, coal prices have gone up 30 percent. Natural gas prices have gone down by a third. These older plants are not operating very much. The relatively attractive outlook for natural gas prices which results from the abundant supply of gas including unconventional gas will enable the Nation to support modernization of the grid in affordable ways. Even so, every analyst that we have seen coming out with estimates of coal plant retirements and future electricity supply indicates that over 50 percent of our electricity supply will eventually come from coal even with these changes underway.

Number five, there are many studies, you have heard about them today, about the amount of capacity that will retire. The more reasonable estimates are the ones that have been prepared recently. These are reflective of the actual rules that are being proposed. The most recent one is the Bipartisan Policy Center's, and that indicates 15 to 18 gigawatts across the country.

Number six, and this is really the most important reason, at the end of the day, you can rely on the industry and its tools to make sure that the lights stay on. We have heard today about system planning. We have heard about least-cost planning from transmission companies and utility companies under the supervision of regulators. There are wholesale power markets where there is underutilized capacity. We have State and federal and grid operators who have an extremely strong record of taking action when necessary to make sure that they meet the obligation to provide reliable supply. Perhaps the most important one is at the end of the day, Congress has already given to the EPA, the U.S. Department of Energy and the Federal Energy Regulatory Commission tools that enable emergency conditions to allow for plants to keep open. The most recent example of this is across the river, the generating station in Potomac was required to stay on under an emergency order from the Department of Energy to keep the lights on for the District of Columbia.

My time is up, and I am happy to answer any other questions.

[The prepared statement of Ms. Tierney follows:]

Testimony of Susan F. Tierney, Ph.D.
Before the U.S. House of Representatives
Committee on Energy and Commerce, Subcommittee on Energy and Power

Hearing on the Impacts of EPA Regulations on Electric System Reliability
September 14, 2011
Summary of Testimony

Good morning, Chairman Whitfield, Ranking Member Rush, and Members of the Subcommittee. My testimony focuses on the impacts of the Environmental Protection Agency's recent air regulations, since these are the regulations that most affect power plants in the near term. These are important regulations from a public health point of view, but can the nation get both the benefits of improved air quality while also keeping the lights on? Will jobs and other economic activity flow from the timely issuance of these regulations? I strongly believe that the answer to these questions is yes, and that the rules should proceed to implementation.

My opinion is grounded in several facts and reasonably certain conditions in energy markets:

1. The U.S. electric industry has a proven track record of doing what it takes to provide reliable power supplies.
2. EPA's Cross-State Air Pollution Rule and Utility Air Toxics come after more than a decade of notice, and allow for more technology options and approaches than expected.
3. The owners of a substantial portion of affected plants have already taken steps to modernize their facilities so that these companies will be ready for the new EPA air regulations.
4. Current fuel market conditions are already putting economic pressure on the older, least-efficient coal plants, which are now operating infrequently and can be replaced with much more efficient power plants. The nation's abundant natural gas supply will help support the modernization of the nation's electric system. .
5. The more reasonable estimates of coal plant retirements are the more recent ones, since they are better informed of EPA's proposals. These indicate that the impacts are manageable.
6. There are various tools already in place to assure that reliability will not be adversely affected. The tools include normal electric system planning, reliability assessments and requirements, diverse market and utility responses, and fundamental safeguards in existing federal laws. This rich set of tools and resources will help lead to economical electricity supplies.
7. Recent market developments provide practical evidence that the impacts of the EPA clean air regulations are manageable.
8. The industry's response to the EPA regulations and market conditions – in the form of investments in environmental control technologies, new power plants, and other responses – will stimulate much-needed economic activity and modernization of the electric system.

Testimony of

Susan F. Tierney, Ph.D.
Managing Principal, Analysis Group, Boston
Before the
U.S. House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy and Power

Hearing:
Impacts of EPA Regulations on Electric System Reliability

September 14, 2011

Good morning, Chairman Whitfield, Ranking Member Rush, and Members of the Subcommittee.

My name is Susan Tierney, and I am a Managing Principal at Analysis Group, Inc., a 500-person economic consulting firm headquartered in Boston, Massachusetts.[1]

I appreciate the opportunity to testify on whether the U. S. Environmental Protection Agency's new and proposed regulations will have adverse reliability impacts on the power sector and electricity users in the United States. I do not think that they will.

Under various existing federal environmental laws, the EPA has made proposals and/or issued final rules to regulate various air emissions, discharges into waterways, and other environmental issues associated with electricity production. The EPA's proposals to replace prior rules (as required by federal courts) do not put the nation in a position of having to choose between public health and keeping the lights on. Both of these important critical national

[1] As indicated on my "Truth in Testimony" form, I am testifying on my own behalf, and neither on behalf of a governmental entity nor a non-governmental entity (other than myself). I have not received a federal grant (or subgrant) or contract (or subcontract) during the current fiscal year or either of the two preceding fiscal years.

objectives can be achieved as EPA moves to implement the Clean Air Act and as the industry responds creatively, responsibly, and cost-effectively so that Americans can get the benefit of clean air and reliable electricity.

This is do-able. My opinion is based on my nearly three decades of public and private-sector experience[2] in electric system economics and regulation and on issues at the intersection of electric system planning, system operations, economic and environmental regulation and performance, and system reliability. My opinion also stems from my analyses[3] of various

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[2] As indicated in my attached CV, I have been involved in issues related to public utilities, ratemaking and regulation, and energy and environmental economics and policy for over 25 years. During this period, I have worked on electric and gas industry issues as a utility regulator and energy/environmental policy maker, consultant, academic, and expert witness. I have been a consultant and advisor to private energy companies, grid operators, government agencies, large and small energy consumers, environmental organizations, foundations, Indian tribes, and other organizations on a variety of economic and policy issues in the energy sector. Before becoming a consultant, I held several senior governmental policy positions in state and federal government, having been appointed by elected executives from both political parties. I served as the Assistant Secretary for Policy at the U.S. Department of Energy from early 1993 through summer 1995, having been nominated by President Bill Clinton and confirmed by the U.S. Senate. I held senior positions in the Massachusetts state government as Secretary of Environmental Affairs (1991-1993); Commissioner of the Department of Public Utilities (1988-1991); Executive Director of the Energy Facilities Siting Council (during the mid-1980s); and Senior Economist for the Executive Office of Energy Resources (during the early 1980s). My Ph.D. in regional planning is from Cornell University. I previously taught at the University of California at Irvine, and recently at the Massachusetts Institute of Technology. I currently sit on several corporate and non-profit boards and commissions, including as a director of EnerNOC, Inc.; chair of the Advisory Council of the National Renewable Energy Laboratory and the Energy Foundation's Board of Directors; a director of the Clean Air Task Force, the World Resources Institute, Clean Air – Cool Planet, and the Alliance to Save Energy; and a member of the Bipartisan Policy Center's energy project, and of the NYISO's Environmental Advisory Council. I serve on the Secretary of Energy's Advisory Board, where I am a member of its Shale Gas Production Subcommittee; and I chair of the Policy Subgroup of the National Petroleum Council's study of the North American natural gas and oil resource base (which is being released on September 15, 2011). Previously, I served as co-chair of the National Commission on Energy Policy; a member of the Advisory Council of the Independent System Operator – New England; a representative to committees of the North American Electric Reliability Council; a member of the National Academy of Sciences' Committee on Enhancing the Robustness and Resilience of Electrical Transmission and Distribution in the United States to Terrorist Attack; and a member of the U.S. Secretary of Energy's Electric Reliability Task Force.

[3] I have published several analyses on this topic in the last year, some of which are co-authored: M. J. Bradley & Associates, LLC and Analysis Group, *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Summer Update 2011 Update*, June 2011 (hereafter referred to as "MBJA/Analysis Group Summer Reliability 2011 Update")(available at http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/MJBA_Reliability_Report_Update_Summer2011.pdf); Susan Tierney and Charles Cicchetti, "The Results in Context: A Peer Review of EEI's 'Potential Impacts of Environmental Regulation on the U.S. Generation Fleet,'" May 2011 (available at http://www.analysisgroup.com/article.aspx?id=12468); Susan F. Tierney, "Electric Reliability under New

studies of electric reliability that have been carried out in the past year, combined with my knowledge of competitive power markets, fuel markets (including natural gas), the processes for permitting and development new energy facilities, and the diversity of ways that the electric industry provides reliable electricity to consumers.

I focus my comments principally on the impacts of two air regulations: EPA's Cross-State Air Pollution Rule ("CSAPR") (previously called the Clean Air Transport Rule ("CATR")), which affects emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") from fossil-fuel power plants in the Eastern half of the U.S.; and the proposed "Mercury and Air Toxics Rule" ("Utility Toxics Rule"), which affects emissions of hazardous air pollutants emitted from most coal- and oil-fired power plants throughout the country. Together, these regulations would replace two rules (the Clean Air Interstate Rule ("CAIR") and the Clean Air Mercury Rule ("CAMR")) previously proposed by the Bush Administration and sent back to EPA by federal courts in order for EPA to revise the regulations to comply with the Clean Air Act. I focus on these two final/proposed air regulations because they will affect existing power plants within the next few years, and EPA's proposed water regulations under "316(b)" of the Clean Water Act would allow for a much-longer compliance time frame and a relatively flexible framework for

EPA Power Plant Regulations: A Field Guide," January 18, 2011 (available at http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide); and M. J. Bradley & Associates, LLC and Analysis Group., *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, 2010 (hereinafter referred to as "MJBA/Analysis Group 2010 Reliability Analysis") (available at http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/MJBA_Reliability_Report_Update_Summer2011.pdf). Additionally over the past year, I have been invited to speak on this topic at conferences sponsored by the National Association of Regulatory Utility Commissioners, the Bipartisan Policy Center, the Massachusetts Institute of Technology, the National Association of Clean Air Agencies, and other organizations.

determining on a case-by-case basis whether thermal power plants will need to install new cooling systems.

The CSAPR and the proposed Utility Toxics Rule are important from a public health point of view. But are they achievable? Can the industry respond effectively on time so that Americans don't have to choose between achievement of the health benefits the Clean Air Act envision and the electric system reliability that underpins the functioning of the U.S. economy? Will jobs and other economic activity flow from the nation's responses to these regulations? I strongly believe that the answer to all of these questions is yes, and that the regulations should proceed to implementation.

Several facts and reasonably certain conditions in energy markets support this conclusion, as I describe in my testimony below:

1. The U.S. electric industry has a proven track record of doing what it takes to provide reliable power supplies to consumers.
2. EPA's CSAPR and Air Toxics come after more than a decade of notice, and allow for more technology options and approaches than previously expected.
3. The owners of a substantial portion of affected plants have already taken steps to modernize their facilities so that these companies will be ready for the new EPA regulations.
4. Current fuel market conditions are already putting economic pressure on the older, least-efficient coal plants, which are now operating infrequently and can be replaced with much

more efficient power plants. The nation's abundant domestic natural gas supply and efficiency resources will help support the modernization of the electric system.

5. The more reasonable estimates of coal plant retirements are the more recent ones, since they are better informed of EPA's actual proposals. These more-recent estimates of coal plant retirements and market responses indicate strongly that the impacts are manageable.

6. There are various tools in place in the industry to assure that reliability will not be adversely affected. The tools include normal electric industry planning, reliability assessments and requirements, diverse market and utility responses, and fundamental safeguards in existing federal authorities. This rich set of tools and resources will help lead to economical electricity supplies.

7. Recent market developments provide practical evidence that the impacts of the EPA clean air regulations are manageable.

8. The industry's response to the EPA regulations and market conditions – in the form of investments in environmental control technologies, new power plants, and other responses – will stimulate much-needed economic activity and modernization of the electric system.

THE INDUSTRY HAS A PROVEN TRACK RECORD ON RELIABILITY ISSUES

The starting point is that the U.S. electric industry has a proven track record of doing what it takes to provide the reliable power supplies. Regulated electric utilities, competitive electric companies, grid operators, and regulators have a strong mission orientation, which combines with regulatory requirements to ensure that reliable electricity supply is a priority.

For many decides, the U.S. electric industry has developed institutions, operating and planning requirements, system plans, operating approaches, emergency response protocols, and billions of dollars of investment to assure reliable electricity supply. The industry is keenly aware that the American economy and standard of living depend upon reliable power supplies. With some notable exceptions, utilities and other electric companies, and their workers, investors, and suppliers, have provided what Americans take for granted and what public officials insist upon: that electricity be reliably available around the clock, with increasing levels of performance to assure worker and community safety and public health.

It is normal practice in the electric industry to look ahead several years to ensure that there will be sufficient supplies available to meet anticipated customer demand under a wide range of contingencies. It can take several years to put in place the new generating equipment, transmission facilities, and other resources needed to ensure adequate supply. Forward-looking assessments by a wide variety of public and private entities provide information about future needs to decision makers in utilities, power generation companies, providers of energy efficiency services, equipment manufacturers, investment organizations, fuel suppliers, public agencies, and others. The norm is decision-making under conditions of uncertainty, given that capital commitments are made years in advance of need, and with only estimates of future fuel prices, demand levels, public policies, and other important factors.

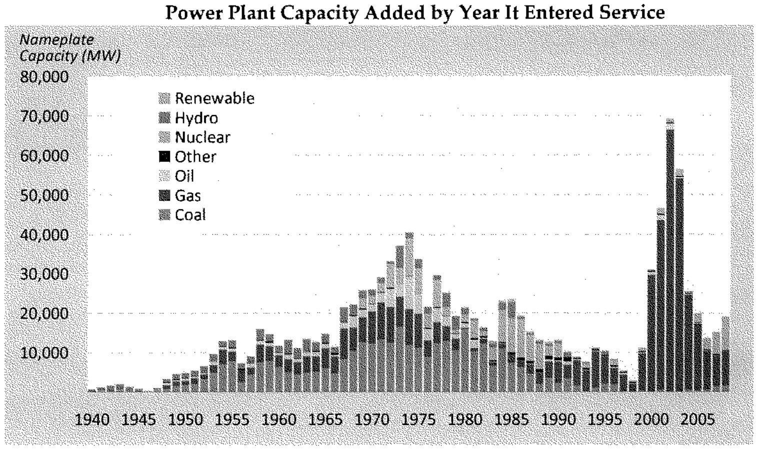
The electric industry has responded well in prior periods (such as the mid-1990s) when Clean Air Act requirements led to investments in new pollution-control equipment and new additions to generating capacity. There were no reliability problems arising from those actions, in spite of concerns raised that there would be equipment shortages and difficulties adding control equipment on so many power plants in a constrained period of time.

Developers of power plant have been able to attract sufficient investment and receive approvals to build far more generating capacity than is anticipated to be needed in the next decade: Between 1999 and 2008, for example, in response to a variety of market, regulatory and economic signals, the electric sector added almost 270 gigawatts ("GW") of natural gas-fired generating capacity, the equivalent of more than 80 percent of the entire existing U.S. coal fleet.[4] Indeed, in just three years between 2001 and 2003, the electric industry built over 160 GW of new generation,[5] many times the amount that analysts project will retire over the next five years (as I describe further below). Much of this capacity remains underutilized today – a fact that can also assist in managing power plant outages required to install pollution-control systems.

[4] EIA, *Annual Electric Generator Report: Form EIA-860*, 2008. Currently, there are more than 17,000 electric generation units in the U.S. with over 1,030 GW of capacity. Using other EIA data, coal-fired generation produced 45 percent of the nation's electricity in 2010, followed by natural gas (24 percent) and nuclear (20 percent), with the remaining amount produced through a combination of hydroelectric power, oil, wind and other miscellaneous fuel types.

[5] *Analysis from:* MJBA/Analysis Group 2010 Reliability Analysis, page 9.

Power Plant Capacity Added by Year It Entered Service



Source: Figure 3 from MJBA/Analysis Group 2010 Reliability Analysis, page 9, with figure sourced from *Ceres, et al., Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States, June 2010.*

EPA'S NEW CLEAN AIR RULES HAVE BEEN ANTICIPATED FOR A LONG TIME, AND EPA HAS PROPOSED RELATIVELY FLEXIBLE COMPLIANCE OPTIONS

By 2011, EPA's CSAPR and Utility Toxics Rule cannot reasonably be viewed as unexpected or a surprise. These regulations have been in the works for several years, with prior incarnations of these regulations (in the form of CAIR/CATR and CAMR) having been known to the industry for many years. And there are many reasons why these regulations will introduce less incremental change than has sometimes been reported:

- The proposed CSAPR would replace EPA's 2005 CAIR, which was initially proposed in December of 2003.[6] In December 2008, the U.S. Court of Appeals for the D.C. Circuit ruled that EPA reconsider its CAIR proposal, but had the rule remain in place until EPA

[6] http://www.epa.gov/cair/rule.html

issued a replacement (which EPA believed, at the time, would take two years to do) to address the Clean Air Act's provisions relating to the transport of air pollutant across state boundaries.[7] EPA issued its newly proposed CATR in July 2010, and finalized the CSAPR in July, 2011.

- Similarly, EPA began its regulatory process relating to mercury emissions in 2003, with the CAMR proposal finalized in March 2005.[8] The Court of Appeals also vacated the CAMR rule in December 2008, and sent it back to the EPA for replacement. EPA issued in newly proposed Utility Toxics rule in March 2011, and is expected to finalize the regulation in November of 2011.
- Several elements of the new proposals allow for flexibility in affected companies' responses. For example:
    - The CSAPR allows intrastate and limited interstate trading of emission allowances for SO_2 and NO_x, consistent with the Clean Air Act:
    - The Utility Toxics rule allows companies with multiple boilers and generating units at a single station to comply by averaging emissions across the units.
    - EPA has proposed a "work practice standard" (with annual performance testing of units using "good combustion practices") to control emissions of dioxins and

[7] http://www.epa.gov/cair/. Also, EPA, "Factsheet: Proposed Transport Rule Would Reduce Interstate Transport of Ozone and Fine Particle Pollution" (available at http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf).

[8] http://www.epa.gov/oar/mercuryrule/rule.html

furans, rather than setting a numeric emissions limit. Together, these various provisions allow for flexibility in meeting the new regulations.

The bottom line is that these new clean-air requirements have been anticipated for a long time. EPA has proposed relatively flexible compliance options to ensure satisfactory compliance by affected companies, the majority of which have already taken steps to reduce their emissions of regulated air pollutants.

MANY PLANTS ARE ALREADY – OR SOON WILL BE – EQUIPPED WITH NEEDED CONTROLS

Many factors besides the current issuance of these clean air regulations have caused owners of many affected plants to take steps to modernize their facilities to reduce their air emissions: many states have already adopted regulations ahead of the federal standards; many of the pollution-control technologies have been tested and are in commercial application; some companies (such as AEP) with facilities affected by the CSAPR and Air Toxics rules, are already under court orders to achieve these outcomes; and many companies have already taken steps to install control appropriate equipments.

EPA's proposed standards for the Utility Toxics rule – which were based on an extensive data collection effort from companies owning coal plants – are do-able.

- Several states – including Illinois, Massachusetts, New Jersey, Connecticut, Delaware, and New York – already impose more stringent mercury-emissions limits on coal-fired power plants than have been proposed by EPA.

- Many of the technologies that are available to satisfy EPA requirements are already in commercially application, with the industry having extensive experience with the installation and operation of these control systems.

- The power plants meeting the proposed standard have a wide variety of pollution-control systems and configurations that are reducing their mercury emissions. Nearly 60 percent of these plants are currently achieving the proposed mercury-emissions standard; nearly 70 percent currently achieve the proposed emissions standard for particulate matter ("PM") emissions; and 73 percent are currently achieving the proposed hydrogen chloride ("HCl") emissions standard.[9]

Many of the companies that own a substantial amount of the nation's coal-fired generating units have recently reported that they are well positioned to comply with the upcoming EPA regulations. Recent corporate earnings statements by chief executive officers of electric generating companies highlight several important themes : (1) companies have long anticipated these rules; (2) early investments have positioned these companies well for compliance; and (3) the impact on electricity rates can be managed. The excerpts below are from the recent analysis I co-authored with MJ Bradley Associates for the Clean Energy Group in June 2011:

- Benjamin G.S. Fowke, III, President and Chief Operating Officer of Xcel Energy, said: "Like many of our peers, we are in the process of evaluating what if any impact [EPA's

[9] This translates to more than 100 units (out of a total of 178) for mercury; more than 119 units (out of a total of 172) for PM emissions; and 158 units (out of a total of 217) for HCl emissions. Note that rather than requiring companies to comply with standards for each individual hazardous air pollutant emitted from coal-fired generating units, however, EPA has proposed the use of "surrogates," simplifying the monitoring and compliance requirements of the rule. For example, PM has been proposed as a surrogate for all non-mercury metal HAPs, including arsenic, cadmium, chromium, and lead. HCl is being used as a surrogate for all acid gas HAPs. No surrogate was used for mercury. MJBA/Analysis Summer 2011 Reliability Update.

Utility Toxics Rule] may have on our operations. Based on our preliminary review we do not anticipate that the rule will require extensive changes to our plans at [Northern States Power] and [Public Service Company of Colorado]...Our proactive steps to reduce emissions through the MERP project in Minnesota and our plans for the Clean Air-Clean Jobs Act in Colorado put us in good position to comply with these rules." April 28, 2011, Xcel Energy Inc. 1st Quarter 2011 Earnings Call.

- Jim Rogers, President and CEO of Duke Energy, said: "[T]he anticipation of more stringent environmental rules has long been part of our business plan. Over the past 10 years, we have spent $5 billion retrofitting existing units with updated emissions controls...Today, approximately 75% of our current coal generation capacity has scrubbers in operation. This will increase to approximately 90%, once our fleet modernization program and related retirements are completed... We have really mitigated a lot of the risk and the cost associated with this program by the early steps that we took." May 3, 2011, Duke Energy 1st Quarter 2011 Earnings Call

- According to Gale Klappa, Chairman, President and CEO of Wisconsin Energy: "We really see very little impact on customer electric rates or our capital plan between now and 2015 as a result of all the new EPA regulations that have been proposed...We might see 1% to 2% increase our best guess. So that gives you an example of how well we are positioned from the environmental standpoint in terms of complying with even the new proposed rule." May 3, 2011, Wisconsin Energy Corporation 1st Quarter 2011 Earnings Call

- Theodore Craver, chairman, president and CEO of Edison International said: "We installed the necessary equipment back in 2009 and are already achieving these [mercury] limits. U.S. EPA's rule contained other draft provisions covering acid gases and non-mercury metals, which we can meet by installing the pollution control equipment we have been planning to use at Midwest Gen to meet our SO_2 emissions commitments to the Illinois EPA." May 2, 2011, Edison International 1st Quarter 2011 Earnings Call

- William Spence, Chief Operating Officer, Executive Vice President and President of PPL Generation, said: "Our proactive approach to environmental compliance positions the PPL fleet favorably for future EPA regulation. Ninety-six percent of the competitive coal generation is scrubbed, 88 percent has NO_x controls already installed." February 4, 2011, PPL 4th Quarter 2010 Earnings Call

- Mauricio Gutierrez, Executive Vice President and Chief Operating Officer of NRG reports that: "The proposed [Utility Toxics Rule] provides flexibility in that compliance can be achieved through facility averaging and company selected control technology. It also recognizes the inherent differences in mercury emissions from lignite coal...[t]he key takeaway is that we do not expect at this time any additional environmental CapEx beyond what we have previously announced." May 5, 2011, NRG Energy 1st Quarter 2011 Earnings Call

- The Tennessee Valley Authority ("TVA"), which owns 17,000 MW of coal-fired generating capacity, announced plans in April 2011 to retire 18 older coal-fired generation units at three power plants (2,700 MW) as part of the utility's vision of being one of the nation's leading providers of low-cost and cleaner energy by 2020. The utility will replace "older and less-economical generation with cleaner sources." Tom Kilgore, TVA's President and CEO, said that a "variety of electricity sources, rather than heavy reliance on any single source, reduces long-term risks and helps keep costs steady and predictable....In the longer term, these actions reinforce our vision to keep bills low, keep our service reliability high and further improve air quality as we modernize the TVA power system." TVA Press Release, April 14, 2011.

At least one more company with a substantial amount of coal-fired generating capacity affected by these air rules is already under court orders to achieve similar outcomes as the new regulations:

- American Electric Power signed a consent decree with EPA and other parties in 2007 in which AEP agreed to retire, retrofit, or re-power most of the units that AEP has recently announced it plans to retire.[10] This reinforces the view that many environmental improvements (and potential plant retirements) have been in the works for some time. In response to questions from an investment analyst, AEP's chief executive officer

[10] Consent Decree entered in the U.S. District Court for the Southern District of Ohio, Eastern Division, with respect to U.S.A and State of New York, et. al. v. American Electric Power et al. (Civil Action No C2-99-1250 (Consolidated with C2-99-1182)), U.S.A. v. American Electric Power (Civil Action No C2-05-360), and Ohio Citizen Action, et. al. v. American Electric Power, et. al. (Civil Action No. C2-04-1098), 2007. The 2007 Consent Decree required AEP to retire, retrofit or repower, by no later than 12/31/2015, 3,900 MWs of the units covered under the decree; of those units, AEP has chosen to retire 3,055 MW and repower 845 MW. In the 2007 Consent Decree, AEP agreed to retire, retrofit or repower 4,500 MWs of its generating capacity. The 2007 Consent Decree covered all units AEP has now proposed for retirement, with the exception of the Welsh unit, whose retirement appears to be related to permitting commitments associated with other generating units in Texas.

recently suggested that the retirements were reasonable: "Throughout I think almost all of 2009 those plants probably didn't run 5% of the time because natural gas prices were such that they simply weren't dispatching. When we shut those down there will be some cost savings as well. And on balance we think that that's the appropriate way to go not only to treat our customers but also to treat our shareholders near and long term with that small amount of the fleet going offline.[11]

ECONOMIC CONDITIONS IN FOSSIL FUEL MARKETS FAVOR NATURAL GAS RELATIVE TO MANY EXISTING COAL-FIRED POWER PLANTS

New, lower natural gas prices are already putting economic pressure on coal facilities even in the absence of EPA regulations. There are many existing and under-utilized gas-fired power plants in the regions that will be affected by the clean air rules. Even taking into account the effects of the post-2008 economic downturn on power plant output, lower gas natural gas prices and higher coal prices to utilities and independent power producers (as shown in the figure below) have meant that gas-fired power plants increased their output from 20 percent of all

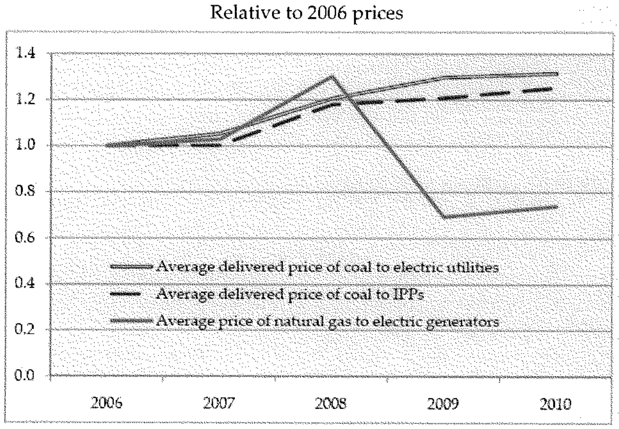
[11] Transcript of Sanford C. Bernstein & Co. Strategic Decisions Conference, June 1, 2011 (available at http://ofchq.snl.com/Cache/A43E47486F11287831.pdf):

Question (by Hugh N. Wynne, Senior Analyst, Sanford Bernstein): "So those [CATR and Mercury and Air Toxics] rules come into effect in 2014 and 2015. AEP disclosed that as a result of those rules there's about 5.5 gigawatts of coal-fired generation capacity that would be vulnerable to closure due to the high cost of compliance. We estimate the output of those plants at about 12 million megawatt hours annually. The generation gross margin associated with AEP's off-system sales would seem to imply that that generation is worth about $150 million or maybe $0.20 a share to AEP. Similarly if you were to lose the capacity revenues owned by Ohio Power on the sale of capacity from those plants it seems to me that about $180 million of annual revenue should be at risk or about $0.25 per share. Does AEP view the risk of the closure of these plants in similar terms? And if so what are your plans to mitigate these potential losses?"

Answer: (Michael G. Morris, Chairman & Chief Executive Officer) "Well this is probably one of those places where I saddle up with the team from FE. If in fact 80 gigawatts close, most of it in the central section of the United States, capacity prices and energy prices will more than adequately compensate us for the 5,500 megawatts going off the line. As you know those are high-cost plants and dispatch infrequently, I am not sure on your 12 million megawatt hours, we can surely supply you with data on that going forward. But, I think that going forward prices of capacity and energy would take care of that. Today – in fact, throughout I think almost all of 2009 those plants probably didn't run 5% of the time because natural gas prices were such that they simply weren't dispatching. When we shut those down there will be some cost savings as well. And on balance we think that that's the appropriate way to go not only to treat our customers but also to treat our shareholders near and long term with that small amount of the fleet going offline."

power production in the U.S. in 2007, to 24 percent in 2010, while coal-fired generation decreased from 50 percent in 2007 to 45 percent in 2010. Gas-fired generation increased in absolute terms, while coal-fired generation decreased in absolute levels over that period.

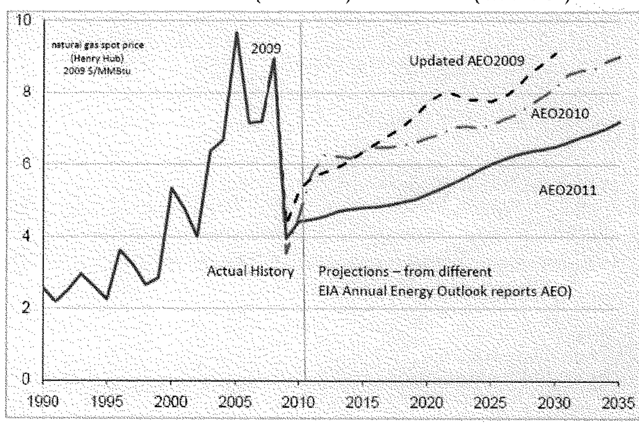
Change in Coal and Natural Gas Prices to Electric Generators
Relative to 2006 prices



Source: Natural gas prices: EIA, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm; Coal prices: William Watson, Nicholas Paduano, Tejasvi Raghuveer and Sundar Thapa, EIA, "U.S. Coal Supply and Demand: 2010 Year in Review," June 1, 2011 (available at http://www.eia.gov/coal/review/pdf/feature10.pdf)

The expectation and availability of relatively low natural gas prices in the future also help favor the replacement of much of the older, less efficient coal-fired power plants that lack emissions controls with new gas-fired generating capacity. The figure below shows the extent to which the availability of greater supplies of natural gas has lowered the Energy Information Administration's outlook for natural gas prices over the last three years (from the 2009 forecast to the 2011 forecast). If conditions were different, the gas-to-coal price differential might mean that it would be economical for the owners of many of the older coal plants to retrofit them with pollution control equipment rather than retire them. Retirement of many of these old, inefficient coal units that lack environmental controls is simply good economic sense.

Natural Gas Prices: Actual (1990-2010) and Forecast (2010-2035)



R. Newall, EIA, The Long-term Outlook for Natural Gas, presentation to the Saudi Arabia – United States Energy Consultation, February 2, 2011

MANY STUDIES HAVE CALLED ATTENTION TO ELECTRIC RELIABILITY ISSUES, WITH THE MORE REASONABLE STUDIES SUGGESTING THAT THE IMPACTS ARE MANAGEABLE.

Many assessments have been published, calling attention to the potential power plant retirements and sending useful information to the markets about needed investment in new capacity in different parts of the country. These studies highlight ranges of impacts under quite-different sets of assumptions. The more reasonable estimates indicate strongly that the impacts are manageable, especially in light of responses already visible in the electric industry. The studies' results do not mean that there will be inadequate resources in the end: rather, they serve as a sort of "call to action" in the marketplace, and several are explicit in saying that they have identified resource gaps in order to signal that action is needed.

My colleagues at MJ Bradley Associates and I performed a review of many such studies last year,[12] on behalf of the Clean Energy Group, and we updated it three months ago, in June of 2011.[13] Additionally, I have analyzed carefully many other reports written on this topic and prepared a "field guide" to their results.[14]

As shown in the table below, many if not most of the studies were performed prior to EPA's issuance of both proposed clean air rules, so did not assume the amount of flexibility built into those proposals.[15] Most assumed a range of scenarios in which there were three basic types of analyses: (a) a base case (no EPA rules, and coal-plant retirements driven by unfavorable economics); (b) a series of "moderate" cases (in which a report's author assumed relative flexibility in compliance options); and (c) "strict" cases (in which the reports' analyses assumed strict, inflexible regulatory compliance). Few if any of the studies examined the extent to which new electric resource options not already formally announced would come forward, and in no case that I am aware of did a study assume that there would be a *robust* market response (including new power plants, implementation of new energy-efficiency and other demand-side

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[12] MJBA/Analysis Group 2010 Reliability Analysis.

[13] MBJA/Analysis Group Summer 2011 Reliability Update.

[14] See also S. Tierney and C. Cicchetti, "The Results in Context: A Peer Review of EEI's "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet," May 2011; and S. Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

[15] This point is made in a recent report published by the Congressional Research Service: "EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?" (authored by James E. McCarthy and Claudia Copeland), August 8, 2011. See page 40.

measures that may now become economical, or even transmission reconfigurations) in combination with the more moderate cases consistent with EPA regulations. Even the results I report below[16], which select the more moderate cases, overstate these impacts for this reason.

Studies of Potential Retirements in Response to Upcoming EPA Air (and Other) Regulations

Study:	**Estimated Coal Retirements:**	**Notes and document title**
PIRA (4/2010)	30-40 GW	PIRA, "North American Environmental Markets Service: EPA's Upcoming MACT: Strict Non-Hg Regs Can Have Far-Reaching Market Impacts."
ICF for INGAA (5/2010)	50 MW	Report prepared by ICF for Interstate Natural Gas Association of America, "Coal-Fired Electric Generation Unit Retirement Analysis."
ICF for EEI (5/2010)	25 GW	(Scenario 1 – CAIR and MACT) Report prepared by ICF for Edison Electric Institute, "Preliminary Reference Case and Scenario Results."
CS (7/2010)	50 GW	Credit Suisse, "A Thought…CATR is First Step in Changing the Coal Fleet."
Bernstein (10/2010)	65 GW	Hugh Wynne et al., Bernstein Research, "U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?"
NERC (10/2010)	6 GW	Based on the "moderate" CATR and MACT cases. North American Electric Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulation."
	25 GW	Based on the "strict" CATR and MACT cases. Same document.
CRA (12/2010)	35 GW	Ira Shavel & Barclay Gibbs (Charles River Associates), "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT."
ICF for EEI (1/2011)	24 GW	Scenario with CATR and MACT (flexibility) Report prepared by ICF for EEI, "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet."
BPC (6/2011)	15-18 GW	BPC's estimate of incremental retirements by 2015, beyond the amount expected by economic conditions; taking into account 316(b) water impacts.
Note: Currently there are approximately 1,030 GW of generating capacity in the U.S., of which approximately 330 GW is coal-fired generation.		

[16] Note that my table does not include an internal "informal staff assessment" prepared by the staff of the Federal Energy Regulatory Commission during the Fall of 2010, and described in an August 1, 2011 letter to Senator Lisa Murkowski from FERC Chairman Jon Wellinghoff and Commissioners Cheryl LaFleur and John Norris.

In my opinion, these estimates likely overstate the impacts of EPA's proposed clean air regulations: for one thing, EPA's regulations are more flexible than had been anticipated by the less-recent studies. And the industry has a wider range of options for responding to capacity needs than was assumed in the studies above. Finally, low gas prices are a fundamental disadvantage for owners of older and inefficient and uncontrolled coal-fired generating capacity.

MANY TOOLS EXIST TO ASSURE RELIABILITY

The industry has various tools to assure that reliability will not be adversely affected. Among others, these include:

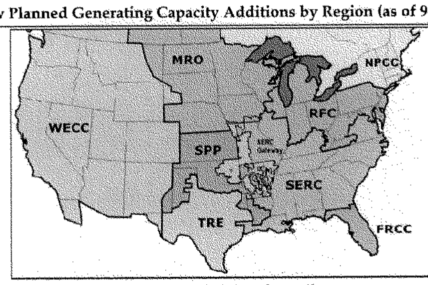
- Well in advance of need for new electric capacity resources, there is considerable information available to decision makers to provide signals about new investment opportunities and needs:
    - Federal administrative procedures inherently provide significant advanced notice of pending changes in environmental requirements.
    - EPA has built into its proposals a reasonable level of flexibility from a technology point of view.
    - Various organizations in the electric industry routinely publish short-term and long-term assessments of resource adequacy, which call attention to situations where additional actions are needed to assure reliable electric supply. Some of these have identified regional markets where inefficient or uneconomic coal

plants may retire. They also indicate amounts of capacity needed from the market (i.e., utilities, competitive power companies and other resource suppliers (e.g., companies providing demand-side measures that reduce the amount of needed new generating capacity)).

- There are long-term capacity planning processes in many of the nation's regional wholesale markets (such as in PJM, NYISO, and ISO-NE) and in virtually all of the areas where state regulators review the resource plans of traditionally regulated utility companies.

- The electric industry has proven experience in adding additional generating capacity, transmission solutions and demand-side measures when and where needed, and in coordinating effectively to address reliability concerns when and where they arise. As shown in the table below, already, 41.5 GW of new plant capacity is under construction in various regions of the country for an in-service date up through 2014 – the year when both the CSAPR and Utility Toxics Rules would be in effect. Another 26.7 GW of generating capacity is in advanced phases of permitting and in-service dates by 2014. (An additional 388 GW of new plant capacity has been announced but I have not included it here, in light of its less-advanced status.) While experience tells us that not all of this capacity will make it into commercial operation, there is a relatively high likelihood of plants already under construction moving forward to completion.

New Planned Generating Capacity Additions by Region (as of 9-2011)



Regional Reliability Councils

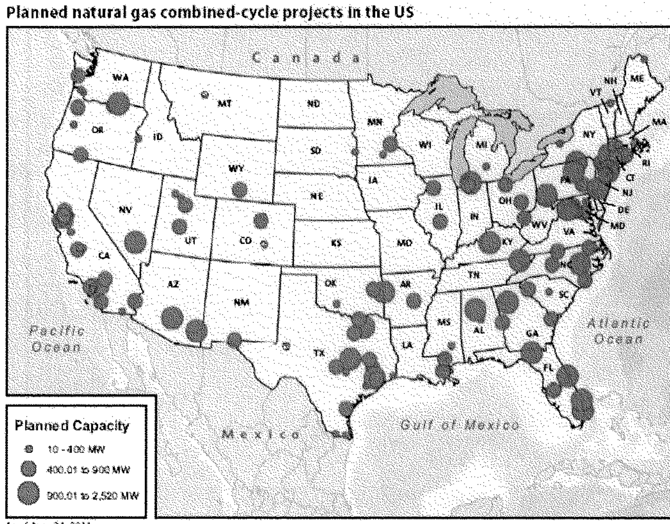
Reliability region	Generating Capacity (MW) Under Construction by Region 2011	2012	2013	2014	2015+	Total	Total by end of 2014:
TRE	453	1,003	-	-	302	1,758	1,456
FRCC	6	46	1,295	-	26	1,373	1,347
MRO	1,094	601	261	-	2	1,957	1,956
NPCC	2,057	1,788	647	640	1,404	6,536	5,132
RFC	2,646	1,892	198	139	47	4,922	4,874
SERC	2,165	6,457	3,615	681	61	12,979	12,918
SPP	580	645	7	-	-	1,232	1,232
WECC	1,613	5,449	4,379	1,109	517	13,066	12,550
Total	10,614	17,881	10,401	2,569	2,358	43,823	41,465

	Generating Capacity (MW) in Advanced Development Phases but Not Under Construction 2011	2012	2013	2014	2015+	Total	Total by end of 2014:
TRE	1	2,030	-	1,000	3,635	6,666	3,031
FRCC	30	48	117	1,395	4,638	6,228	1,590
MRO	225	600	-	-	1,068	1,892	825
NPCC	203	917	1,324	1,187	1,416	5,046	3,631
RFC	101	1,036	859	15	5,250	7,262	2,011
SERC	-	939	29	1,452	10,698	13,117	2,419
SPP	8	777	-	-	763	1,547	784
WECC	944	1,901	4,244	5,341	14,146	26,576	12,430
Total	1,512	8,246	6,572	10,390	41,614	68,334	26,720

Source of data: SNL Financial

- Much of the new power plant capacity under construction or in advanced development is natural-gas combined cycle facilities, which are power plants that are highly efficient and capable of providing power not only around the clock but also in ways that work well with other resources (like wind and solar power) that provide intermittent power. Such facilities take capital investment and less time to permit than new baseload coal or nuclear facilities. As of August 2011, approximately 11.6 GW of new gas-fired combined cycle were under construction with an expected commercial operation by the end of 2014, with another 6.4 GW in advanced permitting. The map below shows this capacity, including another 18.4 GW of announced projects.[17]

Planned natural gas combined-cycle projects in the US



As of Aug. 24, 2011
Source: SNL Energy

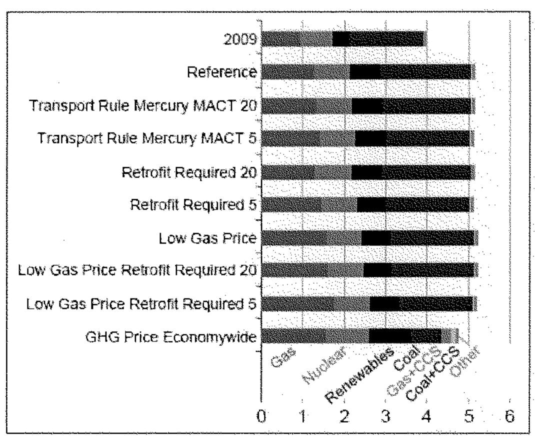
[17] Source: SNL Energy, as of August 24, 2011. An additional 10.8 GW of gas-fired combined cycle projects that are in advanced permitting or announced by project developers, for an in-service date of 2015.

- The availability of abundant domestic natural gas supply is important for enabling the U.S. to rely on currently under-utilized capacity at existing gas-fired power plants (described previously) and on new combined-cycle plants to help meet reliable electricity supplies. The size of the technically recoverable resource base has grown dramatically over the past decade, with the application of new technologies that allow economical access to unconventional gas supply. These abundant resources will be characterized in the new study to be issued publicly by the National Petroleum Council tomorrow,[18] and have been previously reported by various organizations including the U.S. Geological Service and the EIA.
- The availability of natural gas, however, does not mean that coal is not expected to play a significant role in the nation's energy mix. As stated in a recent Congressional Research Service study of the impact of the EPA regulations on the power sector, "Virtually all the analyses agree that coal will continue to play a substantial role in powering electric generation for decades to come. EPA, for example, in the Utility MACT RIA, concluded that coal-fired generation will be roughly the same in 2015 as it was in 2008, despite the impact of the MACT and other rules.[footnote in the original] .... EEI [Edison Electric Institute] projected that coal will be responsible for 36% to 46% of electricity generation in 2020,

[18] As I noted above, I have served as chair of the Policy Subgroup of the National Petroleum Council's fuel study over the past year. The study will be presented to the Secretary of Energy on September 15, 2011, and reflects the work of over 400 participants from industry, academia, states, environmental, and other organizations.

depending on the scenario."[19] Additionally, in the most recent Annual Energy Outlook (2011, released in April 2011), the EIA examined the implications for coal-fired generation under varying assumptions about the degree of stringency in upcoming EPA regulations. EIA concluded that "[d]espite the decline in coal-fired capacity in all the analysis cases above, coal remains the largest single source of generation through 2035 in all but one of the cases" (with the latter case assuming an economy-wide cap on greenhouse gas emissions, which is not part of the EPA proposals and has not been adopted by Congress). These scenarios are depicted in the figure below, from EIA's study:

Electricity generation by fuel in nine cases, 2009 and 2035 (trillion Kwh)



Source: EIA, Annual Energy Outlook 2011, page 51.

[19] Congressional Research Service, "EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?,"(authored by James E. McCarthy and Claudia Copeland), August 8, 2011. See page 40.

- Other tools are available to ensure reliability as time gets closer to compliance deadlines in the EPA regulations:
    - State and federal regulators, and grid operators:
        - State and federal regulations have a strong track record of taking steps necessary to ensure that the companies they supervise are meeting their obligation to provide reliable electric service.
        - As noted in a recent letter by leadership at the FERC,[20] there are active discussions underway by many federal agencies (EPA, FERC, the Department of Energy) with an interest in reliability issues and the EPA regulations.
        - State agencies with responsibility for energy, utility and environmental regulations are in discussions to learn about each others' authorities and potential actions that the various agencies in affected states may take to assure smooth industry responses in their states. The national associations of public officials in those states (the National Association of Regulatory Utility Commissioners, the National Association of State Energy Offices, and the National Association of Clean Air Agencies) are assisting the states in these efforts.

[20] These discussions are described in three letters sent on August 1, 2011 letter to Senator Lisa Murkowski from members of the FERC: from Chairman Wellinghoff and Commissioners LaFleur and Norris; from Commissioner Philip Moeller; and from Commissioner Marc Spitzer.

- At its July 2011 summer meeting, NARUC adopted a second resolution on electric reliability and the EPA regulations, in which NARUC's Board supported a number of actions to assure reliable electricity supply without calling for a delay in implementation of the EPA rules.[21]

- Grid operators (e.g., Regional Transmission Organizations) and regional reliability councils in various regions are conducting studies to assess the timing of reliability issues, and to get ready for additional actions in later years. The grid operators will be able to coordinate scheduling of outages to support reliable operations. Notably, on August 4, 2011, the grid operators that represent systems that serve approximately 146 million Americans requested that EPA include in its final regulations on the Utility Toxics Rule a provision that would "authorizing a targeted

[21] The July 2001 NARUC Resolution closes with the following "resolves" – that NARUC's Board "supports efforts to promote State and federal environmental and energy policies that will enhance the reliability of the nation's energy supply and minimize cost impacts to consumers by:

- Allowing utilities to coordinate the closure and/or retrofitting of existing electric generating units in an orderly manner that will ensure the continued supply of electricity and that will allow power generators to upgrade their facilities in the most cost effective way, while at the same time achieving attainable efficiency gains and environmental compliance; *and*
- Allowing regulatory options for units that are necessary for grid reliability that commit to retire or repower; *and*
- Allowing an EPA-directed phasing-in of the regulation requirements; *and*
- Establishing interim progress standards that ensure generation units meet EPA regulations in an orderly, cost-effective manner; *and be it further*

RESOLVED, That commissions should encourage utilities to plan for EPA regulations, and explore all options for complying with such regulations, in order to minimize costs to ratepayers; *and be it further*
RESOLVED, That FERC should work with the EPA to develop a process that requires generators to provide notice to FERC, system operators, and State regulators of expected effects of forthcoming EPA regulations on operating plants to allow an opportunity for meaningful assessment and response to reliability issues; *and be it further*
RESOLVED, That NARUC and its members should actively coordinate with their environmental regulatory counterparts, FERC, and the electric power sector ensuring electric system reliability and encourage the use of all available tools that provide flexibility in EPA regulation requirements reflecting the timeline and cost efficiency concerns embodied in this resolution to ensure continuing emission reduction progress while minimizing capital costs, rate increases and other economic impacts while meeting public health and environmental goals."

backstop reliability safeguard, on a unit-specific basis, to ensure that the compliance deadlines set forth in the Proposed Rule do not cause electric grid reliability issues that cannot be remedied within the proposed compliance deadline." Notably, these grid operators (including ERCOT, MISO, NYISO, PJM, and the SPP[22]) called for this provision to be included in the final regulations, and not for a wholesale delay in the implementation of the rule.[23]

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[22] ERCOT is the Electric Reliability Council of Texas; MISO is the Midwest Independent Transmission System Operator; NYISO is the New York Independent System Operator; PJM is PJM Interconnection; and SPP is the Southwest Power Pool. These correspond roughly with the following regional reliability councils noted on the map above: TRE (ERCOT); RFC (PJM); SPP (SPP); MRO (MISO); NPCC (includes NYISO, among other regions).

[23] As noted in the comments of ERCOT, MISO, NYISO, PJM and SPP, "RTOs and ISOs are responsible for ensuring the continued reliability of the bulk power system in order to "keep the lights on" to millions of Americans in our respective footprints. ...The RTOs and ISOs are independent entities with no financial stake in any generator or other market participant....[The RTOs and ISOs] urge that the EPA consider authorizing a targeted backstop reliability safeguard, on a unit-specific basis, to ensure that the compliance deadlines set forth in the Proposed Rule do not cause electric grid reliability issues that cannot be remedied within the proposed compliance deadline.....FERC has indicated that due to the deregulated status of generation, the RTOs do not have authority to simply prohibit units from retiring.[Footnote in original] Similarly, under the deregulated structure of the ERCOT market, ERCOT does not have the authority to outright prohibit generation retirements. When an ISO/RTO receives notice of a generation retirement, it assesses the reliability impact....Admittedly, it is difficult to assess the full scope of local and regional reliability impacts absent information from each of the asset owners as to their intentions to retrofit or retire their units. Unfortunately, those decisions are not fully known at this point because they will be driven, in part, by the provisions of the final EPA rules, their relationship to other environmental rules and future market conditions such as the projected costs of competing fuels and forms of generation. Even if overall regional or national levels of capacity remain sufficient, local reliability impacts, the extent of which are still unknown, can have a profound effect on ensuring system reliability within specific areas that can serve substantial load, such as urban areas.[footnote in original] Although the impacts cannot be stated with certainty, given the potential reliability issues that could result from the impact of this rule within the context of several EPA rulemakings, the Joint RTO Commentors respectfully request that the EPA consider revisions that provide for an extension process that would, in essence, allow for the continued operation of units – "Reliability Critical Units" -- identified by the ISO/RTO through its retirement analysis as necessary to maintain grid reliability. ...[T]the extension would be tailored to the specific reliability need, and would only be effective until such time the reliability issue is remedied via the most expeditious and efficient means available, whether that is transmission reinforcements and/or through replacement resources." Joint Comments submitted to the EPA regarding "National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-FiredElectric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, EPA-HQ-OAR-2009-0234, EPA-HQ-OAR-2011-0044, FRL-9286-1, August 4, 2011.

- Some states have begun to call for and review utility plans to comply with EPA regulations and to assure local reliability requirements. Some states (like New York State) have recently updated statutes to support timely reviews of proposals to site new power plant projects. Other states (e.g., California) have experience with streamlining permitting processes to assure timely state agency reviews of plans.

- As a bottom line, there are several fundamental safeguards that prevent reliability problems from occurring in the end. There are many existing statutory authorities and regulatory/risk-management tools that exist to ensure that electric system reliability can be maintained, even as the industry responds to the EPA regulations. Congress has already provided the tools needed to ensure that implementation of regulations designed to protect public health do not end us in a clash with other critical objectives, such as reliable electricity supply. The principal tools that can provide for extra time for compliance, in order to ensure electric reliability, are as follows:

  - Under Section 112(i)(3)(B) of the Clean Air Act,[24] EPA has the ability to extend the compliance deadlines in the Utility Toxics Rule for individual companies for one year on a case-by-case basis, for affected generating units where the owner

[24] "(B) The Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls. An additional extension of up to 3 years may be added for mining waste operations, if the 4-year compliance time is insufficient to dry and cover mining waste in order to reduce emissions of any pollutant listed under subsection (b) of this section."

has taken steps to comply in a timely fashion but still needs more time to assure reliable system operations.

- Under FERC supervision, grid operators can provide financial incentives to companies that file a request to retire a power plant, where such plant closures would raise reliability concerns. There are examples where the parties have negotiated consent decrees to allow continued operation while steps are taken to mitigate the reliability issues. Examples are: PJM's provision of financial incentives to Exelon, the owner of the Eddystone plant in Pennsylvania, to keep that plant in operator pending resolution of reliability issues; and ISO-NE's provision of financial incentives to Dominion, to support continued operation of the Salem Harbor power plant in Massachusetts while steps were taken to address local reliability issues that would arise in the event the plant retired.
- The Clean Air Act (Section 112(i)(4))[25] gives the President of the United States the authority to extend compliance deadlines for the Toxics Rule where such extensions are necessary to assure electric system reliability.
- The Federal Power Act (Section 202(c)) gives the U.S. DOE the authority to override Clean Air Act control requirements in limited emergency circumstances where there is a finding that an electric emergency exists.[26]

[25] "(4) Presidential exemption. The President may exempt any stationary source from compliance with any standard or limitation under this section for a period of not more than 2 years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. An exemption under this paragraph may be extended for 1 or more additional periods, each period not to exceed 2 years. The President shall report to Congress with respect to each exemption (or extension thereof) made under this paragraph. "

- Under such existing legal authority, even a power plant planned to be retired for economic reasons – and not because of EPA regulations – could be required to remain in service pending actions to mitigate the reliability issues. For example, there is a notable recent situation in which the Secretary of Energy used this authority to order that that the Potomac River Generating Station remain in operation so as to assure reliability of the electric supply to the District of Columbia, even though the plant had been found to be in violation of state air pollution requirements. The plant was ordered to remain open until the regional grid operator provided a plan to assure electric reliability. As described in regulatory orders at the time:

> On December 20, 2005, the Secretary of Energy entered an order finding that an emergency exists under section 202(c), and ordered the Plant to generate electricity.[27] The December 20 Order found that an emergency situation exists in

[26] "§ 205.371 Definition of emergency. "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted "entity" will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section 202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[27] Footnote 2 in the original: "U.S. Department of Energy, Order No. 202-05-2 (December 20, 2005) (December 20 Order). Authority under section 202(c) was transferred to the Secretary of Energy in 1980 by the Department of Energy Organization Act, Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. § 7101). *Public Utility District No. 2 of Grant County, Washington*, 95 FERC ¶ 61,338 at n. 49 (2001). Here, we will therefore substitute "Secretary of Energy" for references to the Commission. Section 202(c) states that "[d]uring the continuance of any war in which the United States is engaged, or whenever the [Secretary of Energy] determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the [Secretary of Energy] shall have the authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by

> the Washington, D.C. area, due to shortages in electric energy, facilities for the generation of electric energy, and facilities for the transmission of electric energy, as well as other causes. The Secretary of Energy directed Mirant to operate in a manner that provides reasonable electric reliability but that also minimizes any environmental harm from operation of the Plant.[28]

RECENT MARKET DEVELOPMENTS PROVIDE PRACTICAL EVIDENCE THAT THE IMPACTS ARE MANAGEABLE.

There are already practical signs that the market is responding to the expectation that the EPA clean air regulations will go into effect. Examples include:

- The previously mentioned recent statements of CEOs of companies that own coal-fired generating units, which indicate that their companies are reasonably well-positioned and that the impacts are manageable.
- The expeditious actions of states and utility companies to implement steps deemed to be important for cleaner energy production and public health. A prime example is the recent effort in Colorado to implement a state law (the Colorado Clean Energy – Clean Jobs Law) that required the state's utilities to take actions similar to those required by the EPA's clean air regulations. Within one year of enactment of that act, the state's largest utility (Xcel Energy) had filed plans to comply by shutting down a coal plant and replacing it with a new gas-fired generating station, which the state's public health

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order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."

[28] Source: Federal Energy Regulatory Commission, *District of Columbia Public Service Commission,* 114 FERC ¶ 61, 017 (Docket No. EL05-145-000), Order on Petition and Complaint, January 9, 2006.

agency and utility commission reviewed for compliance with that new law as well as the state's long-standing requirements for least-cost planning.

- The recent results of the PJM May 2011 "forward capacity auction," which confirm that the 13-state PJM region will have ample electricity supply after proposed EPA clean air rules take effect on or before January 2015. This last example deserves a longer explanation, below, because it exemplifies some of the creative ways that the industry is responding to the EPA regulations in conjunction with other long-standing electric requirements.
    - PJM operates the nation's largest integrated power market that includes hundreds of generating units providing electric power to 54 million customers in 13 mid-Atlantic and Midwestern states, as well as the District of Columbia. With over one-sixth of total U.S. generating capacity, PJM is also home to many of the plants that will be affected by the CSAPR and the Utility Toxics rules. Each year, to assure that there is sufficient generating capacity to meet future demand in upcoming years, PJM solicits proposals from power suppliers willing to provide capacity to the market three years forward. The winners in each year's PJM Reliability Pricing Model ("RPM") auction commit to being available to provide electric service during that future time period, and to receive compensation (capacity payments) for doing so.
    - As indicated by the results of the May 2011RPM auction for power supply for the period from May 31, 2014 through June 1, 2015, PJM will have more than enough

capacity to meet federal reliability standards set by NERC in the year in which both the EPA's proposed clean air rules would be in effect. Notably, more than 4 GW of new capacity came into the market with this auction, including new generation and new demand-side resources such as energy efficiency and demand response. This outcome shows the variety of ways in which market participants are providing efficient responses to power requirements as well as environmental requirements.

  - In addition, power companies in PJM (such as AEP and Duke-Ohio) that do not participate in the capacity auction are required to certify that they have adequate capacity to ensure reliable service. These companies have confirmed that they have sufficient electric capacity to meet their needs through June 1, 2015 – more than five months after the EPA rules are expected to take effect.

- In my opinion, the PJM auction results reinforce the fundamental point that the electric industry has the tools to address the retirement of old, inefficient coal-fired units, preserve reliable service for customers.

INVESTMENT BENEFITS RESULT FROM THE INDUSTRY'S RESPONSE TO EPA REGULATIONS, WITH A MORE MODERN ELECTRIC SYSTEM A FEW YEARS FROM NOW

In my experience as a state utility regulator and a state cabinet officer responsible for implementing environmental regulations, I am aware of the tensions that often exist on the eve of implementing new regulations that will impose costs of an industry (and sometimes on the consumers of its products), and the fears that such regulations will lead to jobs losses. Often, though, the very capital investments and expenditures that will be made by the industry to respond to regulatory requirement can – and do - produce positive economic activities in the local and regional communities affected.

I note two recent studies that have examined the job impacts of the EPA's air regulations. One is a report ("New Jobs, Cleaner Air: Employment Effects Under the Planned Changes to the EPA's Air Pollution Rules") published in February 2011 by CERES, and co-authored by J. Heintz, H. Garrett-Peltier and B. Zipperer of the Political Economy Research Institute (PERI) of the University of Massachusetts). The other is a report ("Why EPA's Mercury and Air Toxics Rule is Good for the Economy and America's Workforce") is authored by Charles Cicchetti, Navigant Consulting, July 2011.

The forward to the CERES/PERI study summarizes that "Since 1970, investments to comply with the Clean Air Act have provided $4 to $8 in economic benefits for every $1 spent on compliance, according to the nonpartisan Office of Management and Budget. Since the passage of the Clean Air Act Amendments in 1990, U.S. average electricity rates (real) have remained flat even as electric utilities have invested hundreds of billions of dollars to cut their air pollution emissions. During the same period, America's overall GDP increased by 60 percent in inflation-adjusted terms."

The PERI researchers found that if the electric industry were required to comply with "stringent" EPA compliance rules with capital investments reaching almost $200 billion between 2010-2015 ("including almost $94 billion on pollution controls and over $100 billion on about 68,000 megawatts of new generation capacity), there would likely be net positive benefits:

> Constructing such new capacity and installing pollution controls will create a wide array of skilled, high-paying jobs, including engineers, project managers, electricians, boilermakers, pipefitters, millwrights and iron workers....[B]etween 2010 and 2015, these capital investments in pollution controls and new generation will create an estimated 1.46 million jobs or about 291,577 year-round jobs on average for each of those five years....[T]ransforming to a cleaner, modern fleet through retirement of older, less efficient plants, installation of pollution controls and construction of new capacity will result in a net gain of over 4,254 operation and maintenance (O&M) jobs across the Eastern Interconnection. Distribution of these O&M jobs will vary from state-to-state, depending on where coal plants are retired (O&M job reduction) and where new generation capacity is installed (O&M job gains)."
>
> - Over the five years, investments in pollution controls and new generation capacity will create significant numbers of new jobs in each of the states within the Eastern Interconnection, more than offsetting any job reductions from projected coal plant closures.
> - The largest estimated job gains are in Illinois, (122,695), Virginia, (123,014), Tennessee, (113,138), North Carolina (76,966) and Ohio (76,240).
> - In states with net O&M job reductions, projected gains in capital improvement jobs will provide enough work to fully offset the O&M job reductions. The construction of pollution controls will create a significant, near-term increase in new jobs. O&M job reductions are likely to occur later in the period."[29]

Dr. Cicchetti's study reviewed the EPA's benefit/cost estimates prepared as part of the proposed Utility Toxics Rule, and concluded that the methodology understated the net economic benefits of the proposed rule:

> This report evaluates EPA's benefit-cost analysis as well as quantifies additional benefits that EPA chose not to monetize or include in their final benefit-cost results. EPA's analysis is both comprehensive and conservative, and the proposed Toxics Rule would

[29] CERES/PERI report, Executive Summary.

result in an additional $10.5 billion in annual benefits that EPA did not quantify or include in its analysis.

EPA, nevertheless, concluded that the annual benefits of the proposed Toxics Rule would dwarf the compliance costs, yielding net benefits (benefits minus costs) of about $42 billion to $129 billion per year. Some have argued that EPA's benefit-cost analysis is faulty because it includes co-benefits from SO2, NOX, particulate matter (PM), and greenhouse gas (GHG) emissions, which are not directly regulated by the proposed Toxics Rule. Those who suggest that it is improper for EPA to calculate co-benefits from reductions of non-hazardous pollutants, which are regulated under other sections of the Clean Air Act, have a fundamental lack of knowledge of the core economic concept of opportunity benefits and a poor understanding of how to conduct an benefit-cost or economic impact analysis.1 EPA's benefit-cost analysis is comprehensive and relies upon sound and proven scientific methods and data.

Moreover, EPA's benefit-cost analysis was extremely conservative. EPA ignores the likely overestimate of compliance costs and likely underestimate of realized benefits of the proposed Toxics Rule and fails to substitute a reasonable degree of new energy efficiency and demand-side management. Because it already had enough information to conclude that the benefits of the proposed Rule far outweigh the costs, EPA also chose not to quantify many additional benefits. In this Report, we identify an additional $8.2 billion in annual benefits plus $2.3 billion in likely energy efficiency savings resulting from EPA's proposed Toxics Rule. These include the combined employer business savings for lost workdays, employee recruiting, training, integration, and replacement, and avoided restricted outdoor activities; reduced health care and insurance costs, and increased employment at a time when the economy is stressed. ...This study also examines some of the second and third order effects that EPA did not calculate. The additional analysis in this Report shows that the proposed Toxics Rule would add 115,520 jobs, GDP growth of $7.170 billion, and additional tax receipts of $2.689 billion.

These results are summarized in the following table from the Cicchetti study (executive summary):

	EPA Calculations in Regulation Impact Analysis	Adding Energy Efficiency ($2.3 million in 2015)	Adding Additional Analysis in this Report
Net Benefits	$42 - $129 billion	$44.3 - $131.3 billion	$52.5-$139.5 billion
Job Increases	35,970	n/a	115,520
Healthcare Savings	$3.445 billion	n/a	$4,513 billion
GDP Increases	n/a	n/a	$7.170 billion
Increased Tax Revenues	n/a	n/a	$2.689 billion

CONCLUSION

For these reasons, I strongly believe that the nation does not need to trade off improvements in public health for lower electric reliability. Both of these are essential "givens" for Americans.

I urge the Committee to continue to take interest in this important topic, but to do so with an expectation that the industry will respond innovatively and effectively, and with confidence that Americans can get the benefits of both clean air and reliable electricity. This investment in cleaning up and modernizing the nation's power supply system is important and do-able. In my opinion, there is no reason to delay the implementation of the Clean Air Transport Rule or the Utility Toxics Rule.

Mr. WHITFIELD. Thank you, Dr. Tierney.

Mr. Hanger, you are recognized for 5 minutes.

STATEMENT OF JOHN HANGER

Mr. HANGER. Thank you, Mr. Chairman, Ranking Member Rush and members of the subcommittee. Again, good afternoon. And I have had the privilege to serve Pennsylvania as both a public utility commissioner and more recently as the Secretary of Environmental Protection. The Department of Environmental Protection in Pennsylvania also regulates the oil and gas industry and is responsible for the production numbers that are really rather extraordinary.

The recent discoveries of natural gas from shale formations in Pennsylvania and other States will allow us to tap into a domestic cleaner fuel that can power America into the future. I am proud to have played a role in making Pennsylvania a major producer of natural gas and ensuring strong rules for its production. I think that the promise of this abundant fuel provides an important backdrop to our discussions today and in particular the concern about replacement power generation.

From 2000 to 2008, just in Pennsylvania, 8,000 megawatts of new gas capacity was built. Pennsylvania is located in the middle of the region known as PJM, which spans 13 States and provides electric service to over 58 million people. This past May, PJM conducted an electric generation auction for the 2014–2015 delivery year, which is the first time period in which both the Cross-State Air Pollution Rule and the Mercury and Air Toxics Rule will be in effect. The results of the auction speak for themselves. As a result of the auction, PJM knows that it will have sufficient resources to meet demand during the delivery year and also that it will have a reserve margin of 19.6 percent, which is in excess of the target 15.3 percent installed reserve margin for the region.

Some regulators and companies from other States say the grid cannot manage the retirement of a significant amount of coal generation but I am here to tell you that it can be managed. In Pennsylvania, we have already faced the retirement of some of our coal-fired power plants, and it was done in a responsible, orderly fashion, and the lights stayed on. Back in December 2009, one of our generator operators, Exelon, decided to retire four coal- and oil-fired units with a combined capacity of 933 megawatts at two stations in southeastern Pennsylvania. When they were built, they were state of the art, but they were built during the Eisenhower Administration. They do not produce energy as efficiently as newer technologies and therefore waste energy while they emit dangerous pollutants that sicken and indeed kill people. The EPA was also enforcing rules concerning thermal discharges from these plants.

When Exelon notified PJM of its intention to retire the units by May 2011, PJM said transmission upgrades would first be required to protect reliability. As a result, the EPA, PJM and Exelon worked together to execute a consent order that had two units retire on the original schedule while two others were allowed to run for reliability reasons only for up to another 7 and 12 months, respectively. The Cromby Eddystone example represents a workable model for EPA to follow in resolving similar situations in other

States that may arise as it implements its air quality regulations in the coming years. Indeed, five RTOs have informed EPA that they are willing to assist EPA in identifying where certain plants needed for reliability should be eligible for an extension of time to achieve compliance. These five RTOs have proposed a safety valve or reliability safeguard, and I have attached those comments to my testimony. The RTOs also asserted that they anticipate the reliability safeguard, and this is their language, "would not need to be invoked often, if at all."

In conclusion, I would like to end with a quote from an August 26, 2011, PJM report. The report says, "Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new entry generation demand response and energy efficiency resources may also provide lower-cost alternatives to achieve resource adequacy and local reliability."

Mr. Chairman, across this country, we have some very good news. There is a lot of new generation being built. We focus a lot on retirement of old plants that are inefficient and highly polluting but there are tens of thousands of megawatts of new generation under construction and many more in the planning phase. It is time to get on with this and protect the people's health of this country as well as ensuring that the lights stay on. Thank you, Mr. Chairman.

[The prepared statement of Mr. Hanger follows:]

Testimony of John Hanger

Before the

U.S. House of Representatives Energy and Commerce Committee

Subcommittee on Energy and Power

September 14, 2011, at 9:00 a.m.

2322 Rayburn House Office Building

Chairman Whitfield, Ranking Member Rush, and members of the Subcommittee:

Good morning. My name is John Hanger and I am President of Hanger Consulting LLC. I appreciate the opportunity to speak with you today concerning the Environmental Protection Agency's new and proposed power sector regulations and I hope to share with you some insights gained over 27 years of experience at the intersection of energy and environmental policy.

I have had the privilege to serve Pennsylvania as both a public utility commissioner and, more recently, as a secretary of environmental protection. I was Pennsylvania DEP secretary between 2008 -2011 and a Commissioner of the Pennsylvania Public Utility Commission from 1993-1998. Throughout this time, the electricity industry has continued to improve environmental performance and most of the industry has installed pollution controls that limit the impact on public health and environment. Reasonable environmental regulations have played a critical role in this progress by appropriately pushing and prodding us along.

Today the industry continues to transform and diversify itself. The recent discoveries of natural gas from shale formations in Pennsylvania and other states will allow us to tap into a domestic, cleaner fuel that can power America into the future. I am proud to have played a role in making Pennsylvania a major producer of natural gas and ensuring strong rules for its production. I think that the promise of this abundant fuel provides an important backdrop to our discussions today, and, in particular, the concern about replacement power generation.

I begin by noting that just over 48% of the megawatt hours generated in the Commonwealth of Pennsylvania come from coal-fired power plants. Though our emissions are trending downward, Pennsylvania is currently second highest in the nation for emissions of sulfur dioxide, nitrogen oxide and carbon dioxide. However, as we deploy the nation's largest shale gas deposits, we see a path forward to cleaner generation and job creation that promises to reduce health impacts without affecting reliability.

My testimony will cover three points. First, I will discuss the ability of the PJM states to respond to impending EPA regulations. Second, I will provide a recent example involving two power plants in Pennsylvania that sought to retire but were needed for system reliability. Finally, I will explain how EPA, if it so chooses, could take advantage of this example and extend it to the rest of the country to effectively manage power plant retirements while maintaining reliability.

PJM's Analysis Shows the Region Will Have More than Adequate Resources after the EPA Regulations Take Effect

Pennsylvania is located in the middle of the region known as PJM, which spans 13 states and provides electric service to over 58 million people. PJM is a regional transmission organization that oversees transmission grid operations and operates competitive wholesale electricity markets. In PJM, all electric generation resources are centrally dispatched. That means the system operator, PJM, decides which plants will run during any given hour based on the plant's cost; the lowest cost plants that can serve the need set the price for all wholesale customers in the PJM region. In order to provide a future price signal to ensure that adequate resources will be available, PJM also operates a forward capacity market known as the reliability pricing model or RPM, through which PJM acquires capacity (both generation and demand resources) for a delivery year that is three years into the future. Units that bid in the auction commit that they will be available to serve customers during the delivery year; units that expect to retire before the delivery year do not bid.

This past May, PJM conducted its capacity auction for the 2014/2015 delivery year, which is the first time period in which both the Cross-State Air Pollution rule and the Mercury and Air Toxics rule will be in effect. In that auction, PJM selected offers to serve the region from energy resources including new generating resources, capacity upgrades to existing power plants, new demand response resources, and new commitments to energy efficiency. The results speak for themselves. As a result of the auction, PJM knows that it will have sufficient resources to meet demand during the delivery year, and also that it will have a reserve margin of 19.6 percent, which is in excess of the target 15.3 percent installed reserve margin in the region. In short, PJM has concluded that it does not expect a system-wide resource adequacy problem from the reduction in cleared coal capacity in RPM and from announced retirements.

With a market design like the one FERC has approved for PJM, these conclusions are not remarkable. Forward capacity markets provide price signals for new resources to enter the market when they are needed; and resources that are not economic can ramp down or retire in an orderly fashion. Again, just look at Pennsylvania. Recall that I mentioned that 48% of the MWh in Pennsylvania come from coal-fired power plants. Ten years ago, that number was 57%. How could Pennsylvania manage a 15% drop in coal-fired generation? As a result of PJM's competitive markets, other cost-effective resources have been constructed, and PJM has dispatched them more. For example, during that same period, gas-fired generation has increased from 2% to 13%. Between 2000 and 2008, Pennsylvania's gas-fired generation capacity increased by over 8 GW. And at the same time, Pennsylvania's average residential rates, adjusted for inflation, have decreased, while the national average has increased. The generation fleet has become more diverse, and emissions by the state's plants have dropped considerably. All of these developments are positive. Yet, despite them, the quality of the air breathed by citizens of Pennsylvania still does not meet minimum health standards, due in large part to upwind emissions by power plants in other states that enter Pennsylvania.

Other States Can Manage Fleet Transition; A Pennsylvania Case Study

Some regulators and companies from other states say the grid cannot manage the retirement of a significant amount of coal generation. It is certainly true that electric reliability is critical to the nation's economic health. Our economy depends on the certainty that our electric power supply will be there at all times. Ensuring that the operators of our electricity infrastructure maintain reliable electric service is the responsibility of all energy regulators, both federal and state, and I commend the FERC and state regulators that have appeared here today for their diligence on this front. But I am here to tell you that it can be managed. In

Pennsylvania, we have already faced the retirement of some of our coal-fired power plants and it was done in a responsible, orderly fashion, and the lights stayed on.

Back in December 2009, one of our generation operators, Exelon, decided to retire four coal and oil-fired units with a combined capacity of 933 megawatts at two stations in southeastern Pennsylvania. The four units were:

- *Cromby Unit 1: a 144-megawatt ("MW") coal-fired unit built in 1954;*
- *Cromby Unit 2: a 201-MW peaking unit that can operate on oil or gas, built in 1955; and*
- *Eddystone Unit 1 and Unit 2: combined capacity of 588-MW coal-fired plants built in 1960.*

These plants, while state-of-the-art when built, are now over fifty years old. They do not produce energy as efficiently as newer technologies, and therefore waste energy while they emit dangerous pollutants. For example, Eddystone unit 1 only captures about 34% of the energy in the coal burned in its boilers, while a new combined cycle gas turbine can capture 60% of the energy in the gas it burns. And while all coal- and oil-fired units emit SO_2, NO_x, and mercury, older units like Cromby and Eddystone emit these pollutants at a higher rate than more efficient units. In any event, Exelon concluded that these four units were simply uneconomic given their age and efficiency, wholesale electricity market prices, and new investment that may have been required to meet environmental requirements, particularly with respect to Cromby's heated wastewater discharges. Thus, it concluded that it could not justify the ongoing capital and operating costs that would be necessary to keep them in operation.

Power plant owners within PJM are required to provide notice to PJM of the proposed deactivation of any unit located in that region. Exelon notified PJM on December 2, 2009 of its intention to retire the Cromby and Eddystone units as of May 2011. However, after studying the effect of deactivating the units, PJM advised Exelon that deactivation of Cromby and Eddystone would adversely affect the reliability of the PJM transmission system unless 18 different upgrades to the transmission system were completed.

On March 2nd, 2010, PJM announced the schedule on which the units would be allowed to retire based on the anticipated completion dates of the transmission upgrades. This schedule was subsequently revised to allow the units to retire on the following schedule:

- *Cromby Unit 1 and Eddystone Unit 1 by May 31, 2011 (the original date planned by the owner);*
- *Cromby Unit 2 by December 31, 2011 (7 months later than planned); and*
- *Eddystone Unit 2 by May 31, 2012 (12 months later than planned).*

In other words, PJM concluded that all 18 of the transmission upgrades necessary to allow the plants to retire could be designed, constructed, and placed in service within 29 months of the company's announcement of the decision to retire the units.

As Secretary of Pennsylvania's Department of Environmental Protection (DEP), I would have preferred that the units be permitted to retire on the original schedule, especially if the owner wasn't going to make additional investments in Cromby's wastewater discharge systems. However, I certainly was not in a position to dispute PJM's assessment of the need for the upgrades to be completed before the plants could retire. Ultimately, the DEP and Exelon were able to reach agreement on a consent decree that resolved Exelon's ongoing environmental permitting issues by requiring Exelon to retire Cromby Unit 1 and Eddystone Unit 1 as scheduled on or before May 31, 2011, while authorizing Exelon to operate Cromby Unit 2 and

Eddystone Unit 2 for reliability purposes only until their respective retirement dates. Exelon and PJM agreed to explicit operating procedures that would prevent the dispatch of these units except for "Reliability Purposes," defined as the commitment of the units only "after all [generation] resources have already been committed and additional units are required to help alleviate a 'Transmission Security Emergency....'" Exelon continues to operate the remaining two units pursuant to this agreement today, though at drastically lower levels than they operated in the past. My understanding is that the vast majority of the employees who worked in the plants have either been redeployed within the company or chosen a voluntary early retirement package. As a result of this agreement, the four old, inefficient, uneconomic units will be retired in a manner that protects reliability and achieves substantial improvements to air and water quality.

Lessons from the Cromby-Eddystone Example for Other Regions

Though, as I noted, the Cromby and Eddystone units were not retired as a result of EPA air quality regulations,[1] the Cromby-Eddystone example represents a workable model for EPA to follow in resolving similar situations in other states that may arise as it implements its air quality regulations in the coming years. Indeed, five RTOs have informed EPA that they are willing to assist EPA in identifying whether certain plants, needed for reliability, should be

[1] In the Cromby situation, the Clean Water Act authorized me to impose less stringent thermal effluent limits in a permit than would otherwise be required to meet Pennsylvania water quality standards. If a discharger demonstrates that less stringent limits will assure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in and on the receiving body of water, I was permitted to approve such less stringent limits. Clean Water Act, 33 U.S.C. § 1326(a). Since I was able to conclude that the sequential shutdown of the units under the terms and conditions of the Consent Decree would eliminate future potential violations and was thus sufficiently protective of the water body and its inhabitants, I authorized the plants to continue operation as needed for reliability.

eligible for an extension of time to achieve compliance.[2] These five RTOs, which include ERCOT, are charged with overseeing the reliability of the electric grid serving 146 million Americans. Last month, they joined in comments to the EPA on the Mercury and Air Toxics rule and stated that they do not believe a blanket extension of time to comply is necessary. Rather, together they advocated a framework to ensure that retiring units do not jeopardize the reliability of the electric system. The "Reliability Safeguard" proposed by the Joint RTO Commenters establishes a unit-specific approach to address any local reliability impacts caused by retiring units.

Notwithstanding the otherwise applicable RTO retirement advance notice requirements which range from 45 days to 26 weeks, the Joint RTO Commenters recommend that EPA grant extensions on a case-by-case basis only to "reliability-critical units" that provide at least two years advance notice of retirement. After receiving the two-year advance notice, the RTO would analyze the request through its planning process, and if it determined that the unit was "reliability critical" and the necessary reinforcements or replacement resources would take more than three years to complete, the unit would be granted an extension of time to comply. Under this proposed targeted "safety valve," such units would only be allowed to operate "until the reliability issue is remedied via the most expeditious and efficient means available," but would not be subject to compliance penalties during the extension. Reinforcing the position that this proposed safeguard would only be used in narrow circumstances, the RTOs asserted they "anticipate that [the Reliability Safeguard] would not need to be invoked often, if at all."

[2] The Joint RTO comments are attached as Exhibit A.

As I understand it, EPA has similarly broad authority under the Clean Air Act as I did under the Clean Water Act when I authorized the Exelon units to remain in operation while the transmission upgrades were completed. First, EPA can grant one-year extensions under CAA section 112(i)(3)(B) when necessary for the installation of controls. Assuming this could be interpreted to apply to retiring units, this would give units a total of 48 months to allow replacement generation or upgrades to be constructed. As I noted, all 18 upgrades necessary for Cromby and Eddystone to retire will be completed in 29 months. Second, EPA could negotiate an extension for a reliability-critical unit under CAA section 113(a)(4) and allow an additional one-year grace period in an administrative order on consent. In the extremely unlikely event of a "national emergency extension" under CAA section 112(i)4), the President similarly could authorize an extension for a reliability-critical unit. Finally, in the event that there is an emergency proceeding under section 202(c) of the Federal Power Act, FERC or DOE could authorize an extension for a reliability-critical unit in any order or negotiated consent decree. In short, there are mechanisms to implement the Joint RTO approach and expand the Cromby-Eddystone model to other regions. What is clear, however, is that EPA does not have the authority to issue a blanket extension to all units.

Conclusion

I would like to conclude by citing some of PJM's conclusions from a recent report about the question we are here today to discuss. With respect to the potential for significant coal retirements, PJM noted as follows:

Resource retirement and new resource entry are part of the natural cycle of any well-functioning and competitive wholesale power market. The cycle of retirement and new entry may also help facilitate major policy changes in a more cost-effective manner. Absent resource adequacy and/or local reliability problems, generation retirements are not, per se, an operational negative and may result in enhanced operational reliability and lower costs, taking the public policy context as given. Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus, are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new entry generation, demand response and energy efficiency resources may also provide lower cost alternatives to achieve resource adequacy and local reliability.[3]

In my view, it is time to get on with it, both in PJM and throughout the country. In the event there are local system reliability concerns, the Cromby-Eddystone example demonstrates how power plant owners, RTOs and regulatory agencies can and do find practical solutions to reconcile competing environmental and reliability needs. It demonstrates how important it is for power plant owners to disclose their intended method of complying with impending regulations, whether by retrofitting a plant or choosing to retire it. And it demonstrates how flexibility in environmental regulation exists to allow customized solutions to reliability issues for specific, local circumstances.

EPA should consider the Cromby-Eddystone model as it works to finalize the Mercury and Air Toxics rule. If government and industry work together to work toward compliance with these important rules, we can ensure grid reliability, protection of the public's health, and an orderly transition from uneconomic and environmentally-challenged power plants.

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[3] Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants, p. 33 (Aug. 2011).

Exhibit A

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units	)))))))))	**EPA-HQ-OAR-2009-0234** **EPA-HQ-OAR-2011-0044** **FRL-9286-1**

JOINT COMMENTS OF THE ELECTRIC RELIABILITY COUNCIL OF TEXAS, THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, THE NEW YORK INDEPENDENT SYSTEM OPERATOR, PJM INTERCONNECTION, L.L.C., AND THE SOUTHWEST POWER POOL

Pursuant to the May 3, 2011 Federal Register notice in the above-referenced proceeding,[1] the Electric Reliability Council of Texas ("ERCOT"), Midwest Independent Transmission System Operator ("MISO"), New York Independent System Operator ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and the Southwest Power Pool ("SPP") (the "Joint RTO Commentors") submit these comments on the Proposed Rule in the above-referenced proceeding. These entities are the designated Regional Transmission Organizations ("RTOs") or Independent System Operators ("ISOs") in their respective footprints, having been so designated by the Federal Energy Regulatory Commission ("FERC") or, in the case of ERCOT, the Public Utility Commission of Texas. RTOs and ISOs are responsible for ensuring the continued reliability of the bulk power system in order to "keep the lights on" to millions of Americans in our respective footprints. Together the Joint RTO Commentors serve over 146 million Americans. The RTOs and ISOs are independent entities with no financial stake in any generator or other market participant.

These Comments specifically focus on the compliance timeframe discussed in Section V.M. of the Proposed Rule. The Joint RTO Commentors are not taking a position on the merits of the Proposed Rule or the merits of requests for a blanket delay in its implementation. Rather, the Joint RTO Commentors are concerned about the impacts of the implementation timeline for the Proposed Rule.[2] Accordingly, the Joint

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[1] U.S. Environmental Protection Agency National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial- Institutional, and Small Industrial- Commercial-Institutional Steam Generating Units, 79 Fed. Reg. 24976 (proposed May 3, 2011) (to be codified at 40 C.F.R. Pts. 60 & 63) ("Proposed Rule").

[2] The Joint RTO Commenters note that retirement decisions are affected not just by the instant Proposed Rule but by the costs of compliance with the suite of EPA rules including the Cross State Air Pollution

Exhibit A

Commentors urge that the EPA consider authorizing a targeted backstop reliability safeguard, on a unit-specific basis, to ensure that the compliance deadlines set forth in the Proposed Rule do not cause electric grid reliability issues that cannot be remedied within the proposed compliance deadline.

I. BACKGROUND

A. Description of the Joint RTO Commentors

ERCOT manages the flow of electric power to 23 million Texas customers – representing 85 percent of the state's electric load and 75 percent of the Texas land area. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6.6 million Texans in competitive choice areas.

MISO is the RTO that provides open-access transmission service and monitors the high voltage transmission system throughout the Midwest United States and Manitoba, Canada. MISO operates one of the world's largest real-time energy markets and has 93,600 miles of transmission lines under its direction in a region with an estimated population of 40.3 million.

NYISO is a federally regulated, nonprofit corporation established to facilitate the restructuring of New York's electric industry. NYISO operates a 10,775-mile network of high-voltage lines that carry electricity throughout the state, serving approximately 19.2 million customers, and administers the state's wholesale energy markets. NYISO is responsible for the New York Control Area which is part of the Eastern Interconnection, a vast area of interconnected power systems that cover most of the eastern US and Canada.

PJM serves all or parts of the states of Illinois, Indiana, Michigan, Kentucky, Tennessee, Ohio, West Virginia, North Carolina, Virginia, Maryland, Delaware, Pennsylvania and New Jersey plus the District of Columbia. PJM is responsible for both the planning and reliable operation of the bulk power electric grid serving over 58 million people in its region. PJM manages over 180,000 MW of generation which collectively serves a peak demand of over 158,000 MW.

SPP is based in Little Rock, Arkansas and serves over 6.2 million households, with approximately 15.5 million consumers. SPP provides the following services to members in nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. SPP monitors power flow throughout its footprint and coordinates regional response in emergency situations or blackouts.

Rule, the proposed Clean Water Act section 316(b) cooling water intake rule and the Coal Combustion Residuals Disposal regulation.

Exhibit A

B. The Role of RTOs in Ensuring System Reliability

Pursuant to legislative and regulatory directives, the Joint RTO Commentors are charged with ensuring the reliability of the bulk power electric grid in their respective footprints. FERC Order No. 2000[3] and, in the case of ERCOT, Section 39.151(a)(2) of the Public Utility Regulatory Act and Texas PUC Substantive Rule 25.361(b), charge RTOs and ISOs with ensuring the reliable operation of the grid on a daily basis and planning transmission to ensure long term grid reliability. In performing these functions, the ISOs/RTOs must comply with reliability standards promulgated by the North American Electric Reliability Corporation, and, where relevant, applicable state authority. [4]

ISOs/RTOs do not have authority to build generation or to compel existing generation to operate. Rather, the ISO/RTO model is based on a market platform that provides financial incentives designed to facilitate generation adequacy consistent with applicable reliability standards. By contrast, transmission assets are regulated, and as a result, the ISO/RTOs plan for, and have the authority pursuant to their tariffs to direct, the expansion of the transmission grid to address reliability issues.

Under this construct, ISOs/RTOs receive limited notice of a generator unit's intent to retire.[5] Specifically, the rules of the Joint RTO Commentors provide for the following notice periods:

- ERCOT – 90 days notice for units taken out of service for periods that exceed 180 days (ERCOT Protocol Section 3.14.1.1)
- MISO – 26 weeks (MISO Tariff section 38.2.7 and Attachment Y);
- NYISO – 180 days for generators larger than 80 MW and 90 days for generators smaller than 80MW (NYSPC Case No. 05-E-0889);[6]
- PJM – 90 days notice (PJM Tariff section 113.1 and 113.2);
- SPP – 45 days (SPP EIS Protocols Section 12)

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[3] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) ("FERC Order No. 2000").
[4] The Joint RTO Commenters utilize open stakeholder processes as a key feature of their planning processes.
[5] The limited notice requirements reflect the deregulated status of generation, the competitively sensitive nature of generator intentions and the influence of changing projections of future natural gas prices on generator retirement decisions.
[6] *Proceeding on Motion of the Commission to Establish Policies and Procedures Regarding Generation Unit Retirements, Order Adopting Notice Requirements for Generation Unit Retirements* (issued and effective December 20, 2005); *see also* NYISO Technical Bulletin 185, (establishing procedures for generation unit retirements) at http://www.nyiso.com/public/webdocs/documents/tech_bulletins/tb_185.pdf .

Exhibit A

Moreover, FERC has indicated that due to the deregulated status of generation, the RTOs do not have authority to simply prohibit units from retiring.[7] Similarly, under the deregulated structure of the ERCOT market, ERCOT does not have the authority to outright prohibit generation retirements.

When an ISO/RTO receives notice of a generation retirement, it assesses the reliability impact. There are numerous factors that affect the retirement reliability assessment. These include, but are not limited to, the operating characteristics of a unit, the number of proposed retirements and the location of the units. Based on this analysis, the ISO/RTO will plan transmission upgrades as necessary to ensure reliability limits are respected.[8] Market response solutions, such as the addition of generation, demand response or energy efficiency resources, could also help mitigate reliability impacts of retiring generation depending upon their location and are considered by the ISO/RTO in its public planning process.

C. The Impact of EPA's Proposed Rule

The Joint RTO Commentors are concerned that EPA's Proposed Rule may accelerate the number of generation retirements as generation asset owners assess the costs of complying with this rule in the context of a host of new environmental imperatives being imposed on them. For several, these new requirements could render their assets uneconomic in the ISO/RTO market environment. Environmental compliance is a cost of doing business in a market environment. However, if the impact of the EPA rulemakings increases retirements to the point of creating reliability violations without providing for adequate time to respond to the reliability concerns, this could undermine the reliability of the electric grid for an unacceptable prolonged period.

Admittedly, it is difficult to assess the full scope of local and regional reliability impacts absent information from each of the asset owners as to their intentions to retrofit or retire their units. Unfortunately, those decisions are not fully known at this point because they will be driven, in part, by the provisions of the final EPA rules, their relationship to other environmental rules and future market conditions such as the projected costs of competing fuels and forms of generation. Even if overall regional or national levels of capacity remain sufficient, local reliability impacts, the extent of which are still unknown, can have a profound effect on ensuring system reliability within specific areas that can serve substantial load, such as urban areas.[9]

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[7] *See PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 137 (2005) (where FERC stated: "we are rejecting the specific language . . . that provides that PJM can "require" generators to continue to operate for an indeterminate period, because PJM has not adequately shown that it has the authority to require generators to operate beyond a reasonable notice period.").

[8] Ideally, market based solutions would resolve any reliability issues. However, to the extent the market does not respond, or cannot respond in a timely fashion, the transmission planning process is designed to ensure system capacity is adequate to maintain system reliability.

[9] The Proposed Rule recognized that local reliability impacts were not analyzed. *See* Proposed Rule at 25055.

Exhibit A

Although the impacts cannot be stated with certainty, given the potential reliability issues that could result from the impact of this rule within the context of several EPA rulemakings, the Joint RTO Commentors respectfully request that the EPA consider revisions that provide for an extension process that would, in essence, allow for the continued operation of units – "Reliability Critical Units" -- identified by the ISO/RTO through its retirement analysis as necessary to maintain grid reliability. As described in more detail below, the extension would be tailored to the specific reliability need, and would only be effective until such time the reliability issue is remedied via the most expeditious and efficient means available, whether that is transmission reinforcements and/or through replacement resources.

D. The Scope of Requested Relief

As noted, the Joint RTO Commentors are ***not*** taking a position on the merits of the Proposed Rule itself or the EPA's findings as to the long term health and societal benefits of compliance with the Proposed Rule. Rather, the Joint RTO Commentors proposed remedy is focused on addressing potential reliability impacts resulting from the Proposed Rule which cannot be remedied in time to meet the strict compliance deadlines proposed.

E. The Joint RTO Commentors Proposal for Inclusion of a Reliability Safeguard in the Final Rule

The Joint RTO Commentors also are not asking for a blanket extension of the proposed rule's compliance timeframe. The Proposed Rule provides that existing generators must comply with the final rule no later than 3 years from the effective date of the final rule. A 1-year extension may be granted if pollution control equipment is being installed to achieve compliance.[10] Further, the Proposed Rule would interpret the Clean Air Act such that States can grant the 1-year extension when on-site replacement power is being constructed to replace a retiring generating unit.[11]

Given the potential for reliability impacts due to generation retirements, we ask that the final rule contain a narrowly-drawn reliability "safety valve" such that a retiring generator could be granted an extension for the time needed to implement reliability solutions to replace the subject resource. The Final Rule should define a clear up-front process, such as use of a "pro forma" Consent Decree, to implement this process.[12] Depending on the circumstances, as identified by the ISO/RTO to the EPA, the time period could be for an additional fourth year under the rule or longer if the

[10] Proposed Rule at 25,054.
[11] Proposed Rule at 25,055.
[12] On a unit-specific basis, an agreed date certain would be determined by the RTO/ISO and provided to EPA. The date certain would reflect a realistic estimate as to the time needed for planning and constructing transmission upgrades or securing alternative resources to address the specific reliability challenges being addressed.

Exhibit A

circumstances so require. This "safety valve" would be limited to situations where the following conditions are met:

- The asset owner provides notice of retirement to the ISO/RTO within 12 months of the effective date of the rule, or January 1, 2013, whichever is earlier;

- The ISO/RTO, after analysis through its public planning process, identifies the unit as a "Reliability Critical Unit"; and

- The transmission reinforcements and/or replacement resources (generation, demand response and/or targeted energy efficiency) that are being installed to mitigate the reliability impacts are expected to take more than 3 years to be placed into service.[13]

Linking eligibility for the "pro forma" Consent Decree extension to the provision of an accelerated notice of retirement is key to this proposal. This advance retirement notice could provide at least two years' advance notice of retirement, notwithstanding the substantially shorter timeframes that would otherwise apply, as mentioned. The Joint RTO Commentors believe that timely notice to the ISO/RTO (and potentially EPA) of a unit owner's intentions is critical to ensuring that there is a realistic opportunity for the ISO/RTO to plan and direct implementation of transmission upgrades or ensure adequate alternative resources are available to maintain local and regional reliability challenges that might result from the retirement. The process would apply on a case-by case basis and the Joint RTO Commentors anticipate that it would not need to be invoked often, if at all.

The proposed "safety valve" is intended to provide a "safe harbor" for those retiring generators who meet the eligibility criteria – including providing the advanced notice of retirement – as outlined above. It provides for a process which is clear to all affected parties up front. Moreover, the proposed process is a more cost effective and efficient means to address both environmental and reliability goals without having to resort to last minute appeals to the Secretary of Energy to exercise his authority under Section 202(c) of the Federal Power Act[14] and Section 301(b) of the Department of Energy Organization Act[15] to order the unit to remain operational.

The Joint RTO Commentors stand ready to work with the EPA to ensure that this reliability safety valve is available in the narrow circumstances described above. Incorporating such an approach in the Final Rule will enable the EPA to meet Congress'

[13] The above process is presented as a proposal from the Joint RTO Commenters. The individual RTOs pledge to work with the EPA on the specific implementation details of this proposal as applied to their region.
[14] 16 U.S.C. § 824a(c).
[15] 42 U.S.C. § 7151(b)

Exhibit A

mandate for environmental compliance embodied in the Clean Air Act while also respecting Congress' mandate to ensure the reliability of the bulk power system as per the provisions of the Energy Policy Act of 2005.

Respectfully submitted:

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Mr. WHITFIELD. Thank you, and thank you all for your testimony.

Mr. Wellinghoff in his testimony made it very clear that while FERC had responsibility for reliability, the planning and the detailed analysis of impacts of regulations really occurred at the planning levels and at the State level, the public utility commission levels and so forth. And so we have representatives here today from Georgia, Missouri, West Virginia, Utah and Texas, and every one of you has said that you are concerned about the reliability, you believe there is going to be an increase in cost, and my view, reliability is also an issue when people cannot afford to pay for electricity because they in effect are not receiving electricity, and I think, Mr. Davis, you touched on that yourself because you said there were certain number of deaths in Missouri during the heat spell, and one of the reasons was, people could not afford the additional cost of electricity. Is that correct?

Mr. DAVIS. Yes, it is. Certainly everything points to the fact that they had air conditioning and that they made a conscious decision not to use their air conditioning.

Mr. WHITFIELD. You know, so Mr. Wellinghoff, while I am not going to say he is not concerned about reliability because I am sure he is, but he did not leave us with the impression that this, I am going to call it the Air Transport Rule and Utility MACT, he did not leave us with the impression that he thought it would have a dramatic impact on reliability, but from your testimony, you five, who have responsibility for this, am I correct in that you have great concerns about reliability? Mr. Davis, do you have concerns about reliability as a result of these regulations?

Mr. DAVIS. Absolutely, in certain areas.

Mr. WHITFIELD. Mr. Wise?

Mr. WISE. Mr. Chairman, in our State, we have an integrated resource plan that we do every 3 years, do a 20-year look. We have always been right. That doesn't mean that we couldn't be wrong, but we are concerned about it because of reliability. We heard comments about being able to fire up gas-fired generation. We don't have underutilized gas generation in our State and it does take time to design, build and construct new gas-fired generation. So nothing happens in a vacuum.

Mr. WHITFIELD. Right.

Mr. WISE. So, yes, sir, it is a concern.

Mr. WHITFIELD. Mr. McKinney?

Mr. MCKINNEY. Yes, it definitely is a concern. I talked about overreaching concern about compliance deadlines, and that is really—we just don't have time to make the changes necessary.

Mr. WHITFIELD. Mr. Shurtleff?

Mr. SHURTLEFF. Yes, Mr. Chairman, and what is amazing is that while, as I mentioned, federal law requires the EPA to do this, they have all these tools and all these experts so it really becomes even a federalism issue as far as I am concerned in that they are not—it is not like they are being told to do it alone, they have help, but they are not taking advantage of that, and they could.

Mr. WHITFIELD. Right. And Mr. Doggett, I think you said that you could expect blackouts as a result of this. Is that correct?

Mr. DOGGETT. Yes, sir. We are one of the central planners that the chairman was referring to, and I have concern with this implementation timeline that there will be problems in the near term.

Mr. WHITFIELD. Now, comments were made that EPA is reaching out to States and planning groups to discuss the impact of these regulations. Did EPA reach out to you, Mr. Davis, and talk about these issues?

Mr. DAVIS. No, sir.

Mr. WHITFIELD. Mr. Wise?

Mr. WISE. No, sir.

Mr. WHITFIELD. Mr. McKinney?

Mr. MCKINNEY. No, sir.

Mr. WHITFIELD. Mr. Shurtleff?

Mr. SHURTLEFF. I checked with our agency, and they said no, they have not.

Mr. WHITFIELD. Mr. Doggett?

Mr. DOGGETT. Yesterday afternoon.

Mr. WHITFIELD. Yesterday afternoon? Before the hearing, right?

Now, Mr. Inslee, who is a conscientious, very effective legislator, in his comments earlier today talked about all the job gains that we were going to have because of all this new technology. Now, Mr. McKinney, you and Mr. Shurtleff referred to an analysis conducted of the anticipated job gains or losses as a result of the Air Transport Rule and Utility MACT, and I believe that you said the net loss—that is including gains and losses—the net loss would be something like 1.4 million jobs. Is that right?

Mr. MCKINNEY. That is correct.

Mr. WHITFIELD. Is that what you said also, Mr. Shurtleff?

Mr. SHURTLEFF. Yes, Mr. Chairman. I have the chart before me, a negative 1.88 million, a positive 450,000, so negative 1.4 million.

Mr. WHITFIELD. So, you know, people make comments that we are going to have all these jobs because of new green energy. Yes, there is going to be new jobs but there is going to be lost jobs as well, and particularly in the area—it depends on what area of the country you are living in. And then we have a case like Solyndra where they received a $538 million loan guarantee, they were going to create 1,500 jobs. They got that loan guarantee from the federal government relating to solar panels and now they are in bankruptcy, and the taxpayers are out $538 million.

Well, my time is expired, but Mr. Rush, I will recognize you for 5 minutes.

Mr. RUSH. Thank you, Mr. Chairman.

I want to ask Dr. Tierney, first of all, just a quick question on the unfortunate death of the individual in Georgia. Would you say that that is a problem of reliability or inability to pay rates, and would the LIHEAP program have had an effect, a positive effect on that?

Ms. TIERNEY. Based on my experience not only as a public utility commissioner, a head of an energy office in a State, a former secretary of the environment in a State and the assistant secretary for policy at DOE, I have experience in the LIHEAP program, and while I don't know the particulars at all about this person's unfortunate—or several people, I am not sure, in Missouri, I do know that the LIHEAP program is designed especially to deal with low-income issues relating to winter and summer, cooling and heating.

Mr. RUSH. I might add that some of my friends on the other side have been in opposition to LIHEAP and want to really kill the LIHEAP program off.

But let me move to another area. You have been extraordinary in your conversation relating to job creation, and in your testimony you indicated two reports, and I just want to give you some time to expound on this whole—your item eight on your summary about job creation. What was the overall impact on jobs and investment and technologies from your perspective? Just give us a real thorough evaluation and assessment of job creation.

Ms. TIERNEY. I am happy to do that, and I want to start by talking realistically about the fact that when people are talking about spending money on hardware for pollution control equipment and spending money on building new power plants to replace very old ones, we are talking about infrastructure jobs. We are talking about construction, we are talking about equipment manufacturing. This is heavy industry activity. These are job-creating activities, not to mention issues surrounding green energy jobs. I am not talking about those. What I am talking about is the job creation associated with replacing the kind of capacity that the estimates have said. Now, one of the estimates that I described in terms of my report, I provide information in detail of two studies, one by the Perry Group at the University of Massachusetts that looked at the national estimates as well as one by Professor Charlie Giachetti, and both of these indicate billions and billions of dollars of new investment that goes into jobs in heavy industry and in energy efficiency. As Representative Inslee said, energy efficiency is workers in communities putting on insulation in people's homes. Those are local jobs. And one of the things that we observed in the energy area is that the parts of the country that are very dependent on coal, 98 percent dependent on coal, 90 percent dependent on coal, have had not as much opportunity, let us say, to go after energy efficiency actions in insulating homes of consumers, and the jobs that can be created in those communities associated with putting in energy efficiency and buttoning up the buildings so that people's bills go down, their electricity bills go down, is a real opportunity here.

Mr. RUSH. In August of 2010, you co-authored a report on the electric system reimbursement in the face of impending EPA air pollution rules. You recently updated that report. Can you summarize your new findings?

Ms. TIERNEY. Yes. The most important findings were that there are so many companies that have indicated out loud that they are ready to manage these. We updated it also to indicate that the regulations as proposed are more flexible. They allow for more available pollution control technology than people previously thought, and that led us to conclude that the more recent estimates about the impacts of these regulations are the ones that are more credible for understanding where we stand today.

Mr. WHITFIELD. At this time I recognize Mr. Olson from Texas for 5 minutes.

Mr. OLSON. I thank the chair and I thank the witnesses for coming today. I greatly appreciate your time and expertise.

I am from Texas, so I am going to focus on some of the challenges that we are facing in Texas, and my first question is going to be for you, Chairman Doggett. Thank you for leaving the Lone Star State and coming to Washington, D.C. I know people back home say you are crazy. They say that about me all the time, but we are fighting for Texas.

I want to talk about the Luminant issue, and we have talked about it in the previous panel and we have talked about it here, but because of the CSAPR rules, we are going to lose at least two coal-fired plants in our State, 500 jobs, and I just want to make the panel aware and the committee aware of a letter that was sent from EPA. This is Deputy Administrator Bob, and I am going to mess up his last name, Perciasepe. He sent this to Luminant CEO David Campbell on September 11, 2011, just last Sunday, and the letter says, "We will share with you data that illustrates how Texas Luminant can comply with CSAPR cost-effectively while keeping levels of lignite coal use near current levels, thus avoiding the need to idle plants or shut down mines in response to requirements of the rule." And Luminant's response is: "We are very eager to receive this information. EPA has not yet laid out any specific alternatives that do not involve job losses and facility closures." I mean, shouldn't they have had that discussion with Luminant before CSAPR was being implemented? Mr. Doggett, do you care to respond?

Mr. DOGGETT. I would prefer not to respond relative to job loss but certainly for reliability purposes, I think in discussions with EPA yesterday afternoon, they at this point are willing to sit and look at our numbers that generated the results from our report and let us try to determine why there are differences in the data that they used in preparing the rule versus the data that we are presenting so certainly that dialog would have been helpful.

Mr. OLSON. You would hope they have would that dialog beforehand, before the company announces that they are going to have to close two power plants. I mean, that is absolutely wrong.

Again, to the public utility commissioners, same experience? Mr. Davis? Did the EPA not give you any warning, not consulting you or making promises it is not keeping.

Mr. DAVIS. To my knowledge, to the best of my knowledge, our agency has not received any communications from the Environmental Protection Agency at all.

Mr. OLSON. Commissioner Wise?

Mr. WISE. Yes, we have not, and we are just trying to figure out what the end rules are going to be and how we shoot at a target that we don't know where it is.

Mr. OLSON. And Commissioner McKinney?

Mr. MCKINNEY. To be fair to EPA, there has been several, from a NARUC perspective, several webinars and several discussions, but as far as reaching out individually and trying to understand what the local issues might be and what the real impact is going to be on both reliability and customers, no.

Mr. OLSON. And Attorney General Shurtleff?

Mr. SHURTLEFF. My discussions with my clients over at PUC say they have not had that discussion, although I will point out that Utah has some of the cleanest coal in the world with very little mercury, and we would be able to share with all these folks if President Clinton in 2000 hadn't locked up the Kaiparowits Plateau designation, so we do have clean coal. It is not as big of an impact for us. We are concerned about the nationwide impact.

Mr. OLSON. And so just the committee members know and the American public knows how this decision came about, I mean, and this is in response to that EPA letter, but they based their inclusion of Texas in the final rule on a prediction of a very small contribution from Texas generation to a single air quality monitor, only one, in an Illinois town 500 miles away from Texas. In this location, the EPA established itself that has concluded that it is in air quality attainment based on actual monitored results, but because of EPA, they concede that whatever downwind Texas might cause, it is small and barely meets the statutory threshold and yet they have taken this action that is at least right now going to close two coal-fired power plants.

Dr. Tierney, I want to ask you a question. I greatly appreciate your comments about natural gas and how that is the future of our energy generation in a lot of ways, but I am concerned about EPA because right now they are attacking some of the modern techniques we are using to recover natural gas, and we have got a great example in our home State of Texas where the EPA took over two wells in the Barnett Shale Play and took them from the railroad commission and the operator based on some sort of alleged contamination of drinking water. We did the tests and determined positively that there was no contamination from any sort of natural gas recovery operations near those wells.

If the EPA is able to somehow curtail these techniques, does your model fall apart? Don't we have to have some other source of energy other than natural gas? We have to go back to coal because the wind and the solar, they are not baseline power loads. We have to have some alternative.

Ms. TIERNEY. As you know very well, I am sure, most of the regulation that affects the extraction of natural gas is under State jurisdiction and State law, and so the terms and conditions under which extraction occurs in Texas is under the Railroad Commission. There are environmental issues. I have not heard anything in the past year and a half that I have been working on the National Petroleum Council study in the last 6 months in which I have been working on the Department of Energy shale gas committee in which I have heard EPA is going to shut things down on shale gas extraction.

Mr. OLSON. I will get you some information on the two wells they took over in the Barnett Shale Play. EPA took it over.

I yield back the balance of my time. Thank you.

Mr. WHITFIELD. At this time I recognize the gentleman from Pennsylvania, Mr. Doyle, for 5 minutes.

Mr. DOYLE. Thank you, Mr. Chairman, and I just want to say, I was listening to your remarks and I am sympathetic to the concern about jobs. I think a lot of us feel the same way about some of these trade agreements. I know many Republicans support trade agreements, and where I am come from, NAFTA didn't feel very good in terms of whether it was jobs for Pittsburghers but apparently it created jobs in other parts of the country, and it just seems this is the same kind of issue where there is obviously going to be displacement in certain parts of the country and opportunities in others. So I am sensitive to that.

With regards to your comment about Solyndra, we had administrations in Pennsylvania too that did loan guarantees for an auto company and a television manufacturer that both went belly up and left our State too, but I think we can all agree that we still want to encourage these types of opportunities. They don't always pan out and everyone isn't a winner, but I don't think we should stop trying to bring opportunity and jobs to all parts of the country. I think that is what we all want to do here in the committee.

I want to thank both panels. I am sorry I missed all the fun earlier. I had another meeting and I couldn't get here for the first panel.

Mr. WHITFIELD. It was a little boring.

Mr. DOYLE. Yes, that is what I understand.

But I am especially pleased to see John Hanger here. I want to tell you, Pennsylvania has benefited from his many years both as a public utility commissioner and secretary of our DEP, and we are fortunate to have someone like John here to share his expertise with us.

I was listening a little bit to the earlier panel, and I was rather surprised to see that on the broader issue of reliability, there seemed to be nearly unanimous agreement, which is a rare thing on this committee, that when these EPA regulations go into effect, that the lights are going to stay on. I have been reading some of the comments filed by the RTOs that point out while reliability at large doesn't seem to be a major concern, there is some potential for more localized reliability issues that are going to need to be addressed in a targeted manner.

Mr. Hanger, I would like to ask you, I was looking at PJM's comments to the EPA, and they said specifically PJM proposes that EPA include in its final rule a reliability safety valve for specific units deemed reliability-critical units where an individual unit shutdown would adversely impact local reliability. In your testimony, you seemed to suggest that this may not be needed and you cite your experience with the consent decree with Exelon. Do you believe that similar outcomes, consent decrees, would be expected across the country when needed, or could you expand a little bit on why maybe you think this reliability safety valve isn't necessary?

Mr. HANGER. Well, I agree that the safety valve idea is a good idea. My testimony embraces the point that we already have that kind of authority under current law. We have at least four provisions in the Clean Air Act and the Federal Power Act that allow environmental regulators working with planning authorities like PJM and State public utility commissions, if that is appropriate, to enter into consent decrees, and so I absolutely agree that whenever you retire an individual plant, there is a local reliability analysis that must happen. That is true whether or not we have these rules. There are some plants that are retiring today and we don't have the rules, and I am sure wherever that happened or is in the process of happening, they have gone through a detailed reliability analysis. And we did that at Eddystone Cromby and we found—well, PJM found a problem and they then brought it to me and we worked out with the existing authority a consent order that ensured that the environment was protected and the lights stayed on.

Mr. DOYLE. Very good. So you don't necessarily oppose this idea of a reliability safety valve?

Mr. HANGER. No, I don't oppose the idea.

Mr. DOYLE. Thank you, John.

Mr. McKinney, PJM oversees a portion of the grid that serves 58 million in 13 States including your State and my State. It has a forward capacity market that allows it to know that it has capacity that it is going to need for the future, and recently PJM conducted its auction for the 2014–2015 period. The cross-state and mercury air toxic rules will both be in effect by then. This auction showed that PJM will have more than enough capacity to maintain reliability. More than 4 gigawatts of new capacity will come to the market, mostly demand response, and the reserve margin will be 19.6 percent, which is in excess of the target of 15.3 percent. So based on this auction and additional analysis, PJM stated in its August 2011 report that resource adequacy does not appear to be threatened. West Virginia is in the PJM footprint, and I am just curious, does your Commission have any modeling or analysis that disputes PJM's finding or auction results?

Mr. MCKINNEY. What we do have is, I think if you listened earlier to the FERC commissioners, they talked about local impacts, and local impacts is really many of the issues, and we can reach back just to D.C. recently who chose to shut down two coal plants and have waited a significant number of years to be able to replace those with some other source of generation or some source of transmission. So the issue really gets down to local issues. Yes, there may be—if you have got 10 gigawatts someplace but you can't get it to where it needs to be, it doesn't help.

Mr. DOYLE. Sure. I think we all realize that there is going to be local reliability issues in certain segments.

Mr. MCKINNEY. And that is what I am asking for. I am asking for some sort of flexibility, an ability to be able to move things and allow plants that don't need or you can't justify from an economic point of view to be retrofitted but allow them some safe harbor.

Mr. DOYLE. But you support this concept of reliability safety valve also?

Mr. MCKINNEY. Yes, I do.

Mr. DOYLE. Mr. Chairman, you are generous with your time as always, and I thank you.

Mr. WHITFIELD. Thank you.

Mr. McKinley, you are recognized for 5 minutes.

Mr. MCKINLEY. Thank you, Mr. Chairman.

Mr. Hanger, you had referenced, I think you said in your remarks, I read through your printed remarks but in your oral statement you said that there were two plants or a couple plants that shut down in Pennsylvania. Am I correct on that, something about some plants in Pennsylvania?

Mr. HANGER. Yes, there were two plants, four units, a total of 930 gigawatts.

Mr. MCKINLEY. And did they meet at one time the EPA standards?

Mr. HANGER. They were built——

Mr. MCKINLEY. Yes or no.

Mr. HANGER. At one time in the 1950s and 1960s and 1970s but they were very old plants.

Mr. MCKINLEY. OK. Old plants. I understand. But then you went on, which really caught my ear, you said that they sickened and killed people. Do you have a list of the people they killed?

Mr. HANGER. I can't identify individuals but I——

Mr. MCKINLEY. But you said they killed people.

Mr. HANGER. We can provide you——

Mr. MCKINLEY. That is said around here an awful lot. Everything is pretty loose about these remarks, about it causes asthma, it kills people, but no one gives us names of the people. I don't see the trial lawyers lining up at the doors to chase these people like ambulances. If they really have killed people, I would think someone would have pursued that, don't you think?

Mr. HANGER. They do kill people, and unfortunately, we don't actually know their names. They kill, EPA data shows, up to 34,000 a year.

Mr. MCKINLEY. Thank you very much. You are just like so many other people here.

Mr. McKinney, you have heard a lot of the testimony here, particularly from Dr. Tierney. I know often some of the other panelists would like to respond to some of the comments that have been made, so would you like to respond to Ms. Tierney's comments, her facts and conditions?

Mr. MCKINNEY. And respectfully, I do disagree with Dr. Tierney, and in fact, I have looked at the eight points and I can agree on one point and partially agree on another, but the rest I disagree, so that is two out of eight that I agree on, and I will go on a little background. One of the things we talked about, EPA has had years or decades of notice. Well, these rules are still not totally finalized, and until you see the final rule, there is no way you can make any judgment about what the impacts are going to be, and the second thing is that a substantial portion of affected plants have already taken steps to modernize. That is just not true. There are many plants out there. There are some plants that we have spent $4 billion in West Virginia, and none of those plants meets the new rules. I mean, we have spent money after money trying to make adjustments in SO2, trying to lower and do the right thing. Those obviously have been just not enough.

One of the things I really disagree with is the fact—and I ran—from my former life, I ran coal generation facilities and a chemical, and I recognized, we made study after study trying to decide whether to replace those coal generation facilities with natural gas, and when natural gas was much lower, and it was always what you did is, you took jobs out of the—and replaced that with a lower cost of natural gas at that particular time. We couldn't make it work. But in every case, we showed significant job loss. It was a four to one ratio there, at least, and I think Congressman Shimkus put a slide up that really shows you what that really is about.

Mr. MCKINLEY. Just in closing in the few seconds that I have left, you have heard a lot of folks from the other side try to make this a partisan matter throughout this day, but your registration, how are you registered?

Mr. MCKINNEY. I am a Democrat.

Mr. MCKINLEY. Thank you.

Mr. WHITFIELD. Thank you, Mr. McKinley.

Mr. Green, you are recognized for 5 minutes.

Mr. GREEN. Thank you, Mr. Chairman.

Mr. Doggett, I want to thank you for being here to testify today. The 100-plus-degree temperatures you are experiencing across Texas and then the extreme cold weather we had in February are reminders of how important the role that ERCOT plays in Texas, and I appreciate your working to ensure Texas has the electricity they need to get through the extreme temperatures. For members, in Texas, we have our own grid, and although parts of southeast Texas and parts of north Texas are not part of it, but ERCOT is our agency that controls it.

Mr. Doggett, you are here today to testify about the recent analysis ERCOT conducted on what the CSAPR rule would mean for Texas, the cross-state rule. In doing so, I noticed you did not include how natural gas infrastructure would affect the three scenarios you discussed at length, and I know it may not be feasible for all the plants to switch from coal to natural gas but again, with some of our rich resources we are developing in Texas on the land side, it seems like some of those could be possible. Why didn't you or ERCOT account for natural gas in your analysis?

Mr. DOGGETT. We interviewed each of our resource owners and identified their plans to comply, and in those interviews, that was not presented as a viable compliance option.

Mr. GREEN. If you had accounted for natural gas, how would this have changed your numbers?

Mr. DOGGETT. It would be hard for me to estimate that impact. I did talk to the Luminant owners and we confirmed that switching from coal to natural gas for those units was not an option, but I am unaware of whether that was even an option for the other plants.

Mr. GREEN. I have been told, and I know recently with our heat wave in Houston, there was some natural gas plants taken out of mothballs. I have been told that only 40 percent of those natural gas plants are running. Is that a correct percentage?

Mr. DOGGETT. Forty percent?

Mr. GREEN. I have been told that natural gas plants in Texas only run 40 percent of the time.

Mr. DOGGETT. Natural gas delivers a little over 40 percent of our energy, I am sure off peak because they are not necessary with baseload generation. I am not sure if 40 percent is the number but we economically dispatch the units, so it is likely that they are not running at off-peak times.

Mr. GREEN. Is there any discussion on trying to make the baseline natural gas with prices now at $3.90 per MCF? Because I know baseload, particularly our nuclear power plants, we have two in Texas, and also with coal plants. Is there discussion on trying to do natural gas as a baseload?

Mr. DOGGETT. We had a hearing in Texas yesterday where one entity outside of ERCOT in east Texas highlighted that they were going to reverse their fleet and make their gas units their baseload resources and let the coal units provide the variability. It was really presented as a concern because of the increased cost. I am not here to talk about the increased cost but that was their point, and they also highlighted the concern with increased maintenance and decrease in reliability when you use a unit that was designed for baseload cyclically. That creates maintenance problems.

Mr. GREEN. I understand ERCOT has the authority to utilize reliability must-run contracts with companies. Can you explain what these contracts are and how they can used to mitigate some of the generation capacity we have experienced? I know you have at ERCOT. Is there a way that those contracts can be utilized at ERCOT?

Mr. DOGGETT. There is a possibility. I mentioned earlier that EPA reached out to us yesterday to discuss some options moving forward, and that was one option that they mentioned. The challenge there is that we have to have a method for the resource owner to have some assurance that they will be given a variance from EPA. We certainly can't require a resource owner to break the law.

Mr. GREEN. Texas was included both in the SOx and the NOx and the CAIR program that was rolled out in 2008. while I am incredibly frustrated not only with how the EPA handled the possibility of including Texas but frankly their entire assumption used to justify its inclusion, what do you say to the critics who say that these companies should have been working toward these reductions all along since they were supposed to be stricter standards under CAIR and the Texas ERCOT should have been better prepared for this. How do you respond to that?

Mr. DOGGETT. Well, we analyzed the preliminary rule, and from our analysis of the preliminary rule, it did not appear likely that Texas would be included.

Mr. GREEN. And believe me, I share your opinion on that, and we have had this discussion with EPA for a number of months on both a partisan and bipartisan basis, and it is frustrating.

Bernstein Research examined the issue, finding that if Texas utilities would simply run their existing scrubbers continuously and switch unscrubbed units to lower-sulfur coal, Texas would likely comply with its SO2 budget under the rule in 2012, and do you think that is correct?

Mr. DOGGETT. We have been told by the resource owners that that is incorrect.

Mr. GREEN. Thank you.

Thank you, Mr. Chairman.

Mr. WHITFIELD. At this time I recognize the gentlelady from California, Ms. Capps, for 5 minutes.

Mrs. CAPPS. Thank you, Mr. Chairman.

We know that numerous independent studies conclude that any retirements of old, inefficient coal plants can be offset by large amounts of excess generating capacity, by new capacity that can be quickly built, and third, by demand response and energy efficiency measures that can reduce the amount of generating capacity that is needed at all, but it is always possible that there will be localized reliability challenges caused by retiring power plants, and I want to thank you, Mr. Hanger, for your answers and your responses to Mr. Doyle's questions. You noted a real-life situation that our Republican colleagues are often very worried about. You have demonstrated that the State and the utility and the grid operator were able at least in this instance to work together to keep the lights on while protecting the environment, so I thank you.

Mr. HANGER. You are welcome. Thank you.

Mrs. CAPPS. And I want to turn to you, Dr. Tierney, because Mr. Hanger's response is one approach to dealing with the potential localized reliability challenges, but hopefully there are some other flexibilities available as well to address situations where a plant needed more time and oftentimes this is the question that arises in a local community. They don't have time to assure reliability and the confidence that it engenders.

Ms. TIERNEY. Well, thank you very much for the question, Representative, and there are quite a few instances of situations where a plant was going to retire for economic reasons or for environmental reasons, and it was found in the local reliability studies to be a problem if there were a retirement. I can think of an example in Massachusetts where there was a consent decree negotiated between the environmental regulators and the owner of the plant in conjunction with a must-run contract, very similar to what happened in Pennsylvania, kept the plant operating while there were remedies put in place. Transmission upgrades were put in place. Demand management was put in place to reduce the demand in the area.

Another example is one that I mentioned previously across the river at the Potomac River Generating Station where Virginia, the State regulators were interested in having that polluting plant be shut down. The company wanted to shut it down. There were applications made to the Department of Energy to use its emergency authority under existing law to find a condition under which the plant could not be retired, and PJM came up with studies of transmission and transmission was put in place along with other alternatives besides just shutting down the plant to keep that plant operating during the period of the other remedies. Those are now in place, and the plant looks like it will be shutting down by voluntary action of the owner.

Mrs. CAPPS. So there are some varieties of localities where the remedies have been put into place that satisfy the local people. Would you like—you might want to take a minute to comment on Mr. McKinney's statements in this regard to local reliability.

Ms. TIERNEY. I could not agree with him more than local reliability issues are fundamental and important, and as one of the other panelists, John Hanger, said when there are—when there is an addition to the grid in terms of a new power plant or removal of a power plant from the grid, there are always local reliability studies. Those have to be done. And if there were to be a problem, the existing authorities will allow these varieties of tools in place to make sure that the lights stay on.

Mrs. CAPPS. Thank you. And finally, I think this is the last question here, and this is fundamental to me, opponents of the EPA's public health and environmental protections are often essentially arguing that we have to choose between public health protections and the reliability of our electric grid. I have to give away too that I am a public health nurse in my background. There is only a minute left, but Mr. Hanger and Dr. Tierney, my question, are these goals really in tension? Do we have to choose at the local level between reducing toxic pollution and keeping the lights on?

Mr. HANGER. I will go first, since I am afraid the Congressman took offense to my language. The language I am afraid reflects the truth. Old coal-fired power plants do emit pollution that can cause health damage. That is why we have these rules. We are not doing this just to harass the coal industry or any other industry. This is about human health. And they are not in tension. That is what has been demonstrated in Pennsylvania. It has been demonstrated in many States. We have ways to clean up the coal plants so they can continue to operate. We can build new coal plants that don't cause that damage and we have alternative fuels, and we just should get on with it.

Mrs. CAPPS. Thank you.

Any further comments from you?

Ms. TIERNEY. He said exactly what I would have said.

Mrs. CAPPS. And also from my background, the cost of damaged health to employees, to neighborhood families, we haven't really stopped to figure out exactly how that fits into this balance as well so that when we assess the cost, we need to look at a wide circumference, and maybe some of the rest of you would agree. I have 29 seconds—oh, no, I am over. Thank you.

Thank you, Mr. Chairman.

Mr. WHITFIELD. Thank you very much, and I want to thank——

Mr. RUSH. Mr. Chairman, before we conclude, I have a unanimous consent request.

Mr. WHITFIELD. OK.

Mr. RUSH. I can't help but just notice this young lady, I think this is Mr. Davis's daughter.

Mr. DAVIS. That is correct.

Mr. RUSH. She has been so well mannered and so attentive to this proceeding that I just think that we should just give her a round of applause.

Mr. WHITFIELD. What is her name?

Mr. DAVIS. Micah Davis.

Mr. WHITFIELD. And has she always been this interested in environmental issues?

Mr. DAVIS. For the last 2 or 3 years, she has been following me around.

Mr. WHITFIELD. I also have a unanimous consent request on behalf of Mr. Murphy, who is a member of this committee. He wants to submit for the record the Pennsylvania Department of Environmental Protection's comments regarding the Utility MACT rule and also PJM's comments on this rule as well, so I will admit that into the record.

[The information follows:]

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SECRETARY

August 4, 2011

U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Mail Code 2822T
Attention Docket ID No. EPA–HQ–OAR–2009–0234
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units (Docket ID No. EPA–HQ–OAR–2009–0234)

To Whom It May Concern:

The Department of Environmental Protection (Department or DEP) appreciates the opportunity to submit comments on the U. S. Environmental Protections Agency's (EPA) "National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Proposed Rule," published in the *Federal Register* on May 3, 2011 (76 *Fed. Reg.* 24976). The EPA is proposing national emission standards for hazardous air pollutants (NESHAP), including mercury, which are emitted from coal-and oil fired electric utility steam generating units (EGUs) under Section 112(d) of the Clean Air Act (CAA or the Act) (Utility MACT) and revised new source performance standards (NSPS) for fossil fuel-fired EGUs pursuant to Section 111(b) of the CAA. The Utility MACT Rule will apply to new and existing electric generating units (EGUs) including fossil fuel-fired combustion units of more than 25 megawatts that serves a generator that produces electricity for sale.

The Department understands the need to substantially reduce hazardous air pollutants (HAPs) including mercury from EGUs in accordance with Section 112 of the CAA. However, certain provisions in the proposed Utility MACT must be addressed prior to final rulemaking. Issues of particular concern including the overly stringent hydrogen chloride (HCl) limits which would adversely affect the operation of coal refuse plants in Pennsylvania and the burdensome performance testing and sampling frequencies are discussed herein.

I. <u>Coal Refuse Definition for Waste Coal Burning EGUs</u>

Pennsylvania has many abandoned coal mines and coal refuse piles that generate many adverse impacts upon surrounding land and water. For example, concentrated levels of acid mine drainage is released into local waterways; unstable stockpiles may collapse and threaten the safety of nearby communities; and the scenic and recreational quality of the landscape is ruined. Circulating fluidized bed combustion technology has been utilized to remedy this legacy and to provide the nation with an alternative source of energy. Pennsylvania law recognizes and encourages the combustion of waste coal as an important form of energy production. Since 1987, coal refuse plants in Pennsylvania that use CFB technology have collectively removed and converted millions of tons of coal refuse in a highly regulated, managed manner to reclaim thousands of acres of damaged mine lands and streams. Moreover, these cogeneration plants have converted this coal refuse into electricity to meet the energy needs of hundreds of thousands of households and businesses. In addition to transforming waste coal piles into energy, coal refuse facilities produce a beneficially useful solid ash product which, with its alkaline quality and binding characteristics, is ideal for reclaiming abandoned mine lands because it binds with other reclamation materials and prevents migration of heavy metals and other pollutants that are the vestiges of historic mining activity. Therefore, EPA's final Utility MACT rule should not establish HCl limits that would adversely impact the environmental beneficial use of waste coal.

In the proposed Utility MACT Rule, EPA is proposing to subcategorize coal combustion based on the British thermal units (Btu) per pound of coal, on a moist, mineral matter-free basis. In the proposed rule, "coal refuse" is defined as "any by-product of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis." However, the DEP believes that the final Utility MACT Rule should adopt the NSPS "coal refuse" definition in 40 CFR 60.41Da (relating to definitions). As defined in section 60.41Da, the term "coal refuse" means "waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material." The NSPS definition of coal refuse is recommended because waste coal has a high variability in chemical properties such as heat content, percent ash, sulfur, chlorine, and moisture. If EPA requires consideration of the ash, the waste coal will not consistently meet the proposed "coal refuse" definition.

The DEP is also concerned that the majority of the well-controlled circulating fluidized bed (CFB) combustion units in Pennsylvania cannot meet the stringent hydrogen chloride (HCl) limits, 0.002 lb. HCl/MMBtu, in the proposed Utility MACT Rule. Due to the uniqueness of the coal refuse, it is burned in CFB combustion units which do not employ the same type of control for acid gases that pulverized coal burning units employ (i.e., wet flue-gas desulfurization units). Typically, bituminous "gob" contains higher levels of sulfur than anthracite culms. The acid gases, in CFB units are controlled by *in situ* limestone injections. Most of the well-controlled CFB units burning coal refuse would not be able to comply with the proposed HCL emission limits. There are fourteen CFB facilities in Pennsylvania that burn waste coal (anthracite culm and bituminous "gob") in circulating fluidized combustion units which utilize combustion zone limestone injection for the control of acid gases. DEP has reviewed the continuous emissions monitoring data for these fourteen facilities and has found that the majority of these facilities will not meet EPA's proposed SO_2 surrogate emission limit of 0.20 lb/MMBtu. In addition, there is a waste coal-burning facility in Pennsylvania that operates an additional polishing unit for acid gas control. However, even with the addition of this advanced polishing acid gas control system, this CFB unit cannot meet the proposed SO_2 limit of 0.20 lb/MMBtu. The Department urges EPA to reconsider the proposed HCL and surrogate SO_2 limits, which are not achievable for certain EGUs including units operating with acid gas controls.

II. Proposed Non-Hg HAP Metals

The Department believes that using total particulate matter (PM) as the surrogate for non-mercury metal HAP emissions is appropriate because most, if not all, non-mercury HAP metals are entrained in the flue gas fly-ash such that effective PM controls will also effectively capture the non-mercury metal HAP constituents within the total PM. The DEP recognizes, however, that smaller size particulate matter (e.g., $PM_{2.5}$) may be a better indicator due to preferential partitioning of non-mercury metal HAPs in the smaller size fractions of total PM. As EPA indicates, test methods for $PM_{2.5}$ in flue-gas are not applicable to all exhaust stack conditions. We also recognize that operating a PM CEMS to measure particulate matter as a surrogate for non-Hg metal HAPs does not account for condensable particulate matter collected during the initial testing for total particulate matter. Therefore, DEP recommends that EPA develop more broadly applicable $PM_{2.5}$ performance test methods that can replace total PM as the non-mercury metal HAP surrogate, to the extent feasible. DEP data collected during source testing of coal-fired EGUs in 2009 demonstrates that the condensable portion of the total particulate matter in coal-fired EGUs without wet scrubbers may account for approximately 70% of the total particulate emissions. This testing was conducted using the current version of EPA's Reference Method 202 – Dry Impinger Method for Determining Condensable Particulate Emissions from Stationary Sources.

III. Burdensome Requirements for Performance Tests

As proposed in section 63.10006 (relating to when must I conduct subsequent performance tests, fuel analyses, or tune-ups) of the Utility MACT Rule, the monthly and/or bimonthly performance test requirements for certain units operating without PM, HCl and Hydrogen Fluoride (HF) continuous emission monitoring systems (CEMS) are unduly burdensome for industry and regulatory agencies. In addition to reviewing and approving protocols for source testing, the number of source test observations increase significantly. The DEP currently perform approximately 595 source test reviews annually and manages over 1,000 Department-certified continuous emission monitoring systems. The initial performance test for facilities affected by the proposed Utility MACT Rule would add approximately 400 performance tests in order to comply with initial and bimonthly performance test requirements. In addition, the Department would also be required to review protocols and test results for Low Emitting EGU (LEE) testing. These burdensome requirements will increase by 70% the total number of test review s conducted by the Department. The proposed Utility MACT Rule would also add 144 new CEMS that must be certified and managed by the Department. In addition, DEP is obligated by the EPA Air Facility System (AFS) Information Collection Request (ICR) of 2005 to report results of testing within a 60 day period. Source operators however are allowed to send the results to the DEP within 60 days following the completion of the source test. The increase in testing activity as well as frequency would create a difficult to manage backlog of test reports, which must be reviewed for compliance purposes. DEP recommends that the monthly and bimonthly testing requirements for coal and solid oil derived fuel units in Section 63.10006 be revised to allow quarterly or biannual testing requirements in order to provide a reasonable timeframes for the owners and operators of affected units and state and local agencies to maintain robust testing and review procedures. The frequency of testing could be established based on the levels of emissions determined by initial test results. DEP also suggests that once the initial performance test is conducted for PM (filterable and condensable) and non-Hg HAP metals, and fuel sampling and/or operating parameters are established, fuel sampling would be a simpler approach instead of requiring excessive performance testing. A third consideration would be to offer source operators the ability to submit a Compliance Assurance Monitoring (CAM) Plan that would provide correlation based limits to assure continuous compliance with established emission limits.

IV. Particulate-bound Mercury; Appendix A to Subpart UUUUU

EPA's proposed Utility MACT Rule allows facility owners and operators to ignore particulate-bound mercury emissions when using a CEMS to quantify emissions, as indicated in the proposed Appendix A to Subpart UUUUU – Hg Monitoring Provisions (which only accounts for vapor phase mercury emissions). Demonstrating compliance without accounting for particulate bound mercury is not appropriate because particulate-bound mercury can constitute a substantial fraction of total mercury emissions. The DEP has determined that the filterable portion of total particulate emissions for coal-fired EGUs without wet scrubber controls can produce an average of 30% filterable particulate matter. The EPA should require total mercury emissions to be the basis of compliance demonstrations by taking into account the average particulate bound mercury measured during the most recent stack test on that unit in combination with the total vapor-phase mercury measured by the CEMS until such time as mercury CEMS to measure particulate-bound mercury are installed at a unit. To ensure the full extent of achievable mercury reductions, EPA should require a methodology that quantifies total mercury in all forms.

V. Low Emitting EGUs

EPA's proposed Utility MACT Rule allows for existing facilities to qualify for LEE status for mercury emissions based on testing using Method 30B, a vapor phase only test method, which does not account for any particle bound mercury emissions. DEP recommends that an initial performance test for mercury emissions include an accounting of any particle bound mercury. An option would be to demonstrate that total mercury emissions is less than 10% of the mercury emission limit or less than 22 pounds per year using a test method that measures total mercury. If the particulate bound mercury is 5% or less than the total, subsequent testing could measure only the vapor phase mercury emissions. If EPA Reference Method 29 or ASTM Method D6784-02 (2008) is used to determine total mercury emissions, only three one-hour test runs would be required.

VI. Grid System Security and the Need for Flexibility

It is our understanding that Regional Transmission Organizations (PJM for example) have submitted comments relating to ensuring electric grid reliability. Also, the Pennsylvania Public Utility Commission has filed comments raising concerns regarding electric grid reliability as well. We urge EPA to give those comments and concerns serious consideration. The Preamble to this proposed rule states that EPA believes and predicts, as of the time that the proposed rule was published on May 3, 2011, that the requirements of the proposed rule can be met without adversely impacting electric grid system reliability. As PJM and others have pointed out, there is reason to question this sanguine outlook especially with respect to potential adverse impacts on grid system security, *i.e.*, delivery of power to consumers, and EPA's actually now-demonstrated understated level of expected generation retirements. Indeed, EPA's proposed rule recognizes that its analysis did not address what it calls "localized transmission constraints." Also, we now have actual empirical data that post-dates the publication of the proposed rule which shows that considerably more megawatts of generation are expected to be retiring than EPA projected.

Also, EPA's prediction in the Preamble to this rule seems to be limited to this proposed rule, and we will not know the synergistic impact on reliability of the entire suite of rules that are coming down from EPA either right now or in the very near future which will have an impact on electric generating units. The only thing we can be sure of now is that we cannot be sure what impact this rule, along with the other rules in the pipeline, will have on the reliability of the electric grid delivery system until later when we see the actual impact of the proposed rule and the other rules as they are implemented. Thus, we urge EPA to build in some real time flexibility to state environmental permitting authorities in the final rule (and the other rules as well) with respect to timing of the requirements imposed by the rule should reliability impacts be more adverse than EPA currently seems to anticipate.

Thank you for the opportunity to comment on the proposed rule. Should you have questions or need additional information, please contact Kenneth R. Reisinger, Acting Deputy Secretary for Waste, Air and Radiation Management, by email at kereisinge@pa.gov or by telephone at 717 772.2724. You may also contact Joyce E. Epps, Director of the Bureau of Air Quality, by email at jeepps@pa.gov or by telephone at 717.787-9702.

Sincerely,

Michael L. Krancer
Secretary

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

National Emission Standards for	)	
Hazardous Air Pollutants From Coal and	)	
Oil-Fired Electric Utility Steam	)	**EPA-HQ-OAR-2009-0234**
Generating Units and Standards of	)	
Performance for Fossil-Fuel-Fired	)	**EPA-HQ-OAR-2011-0044**
Electric Utility, Industrial-Commercial-	)	
Institutional, and Small Industrial-	)	**FRL-9286-1**
Commercial-Institutional Steam	)	
Generating Units	)	

CORRECTED COMMENTS OF PJM INTERCONNECTION, L.L.C.

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Dated: August 4, 2011

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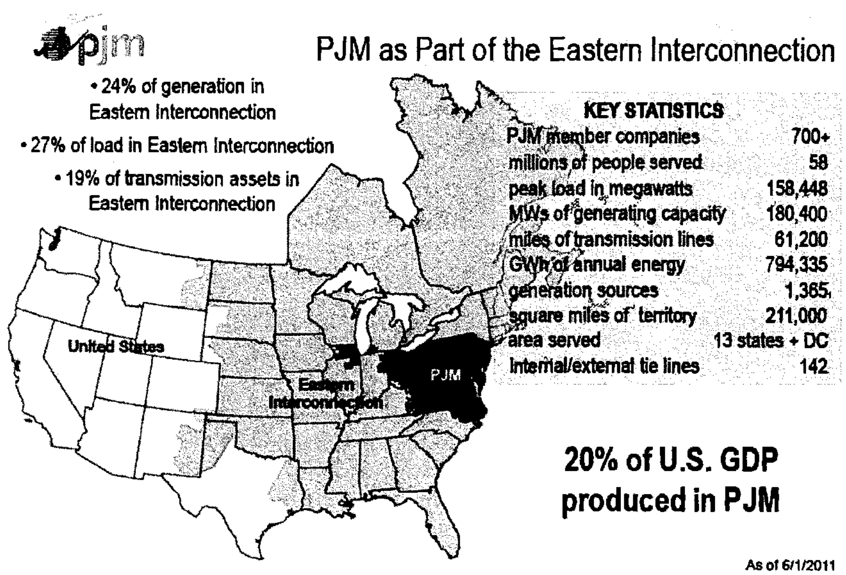
CORRECTED COMMENTS OF PJM INTERCONNECTION, L.L.C.

PJM Interconnection, L.L.C. ("PJM") files these Comments in response to the EPA's Notice of Proposed Rulemaking of the United States Environmental Protection Agency ("EPA") in the above referenced proceeding. PJM is the Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO") serving all or parts of the 13 states of Illinois, Indiana, Michigan, Kentucky, Tennessee, Ohio, West Virginia, North Carolina, Virginia, Maryland, Delaware, Pennsylvania and New Jersey plus the District of Columbia. PJM operates the largest competitive wholesale market in the nation and is responsible for both the planning and reliable operation of the bulk power electric grid serving over 58 million people in its region. PJM manages over 180,000 MW of generation which collectively serves a peak demand of over 158,000 MW. The PJM region, depicted below, encompasses 24% of all of the generation in the Eastern Interconnection, 27% of the load and 19% of the total transmission assets in the Eastern Interconnection. Approximately 20% of the U.S. Gross Domestic Product is produced in the region served by PJM.



EXECUTIVE SUMMARY OF COMMENTS

PJM submits these comments with respect to the compliance timeframe contained in Section V.M of the Proposed Rule.[1] PJM appreciates the Proposed Rule's recognizing the need to maintain system reliability and the agency's pledge in the Proposed Rule to work with RTOs and others to ensure that its Final Rule does not adversely impact system reliability.[2] However, PJM is concerned that, with respect to those generating units which PJM identifies as Reliability Critical Units, the current compliance timeframe could severely impact reliability unless such units are provided a limited extension of time to comply. "Reliability Critical Units" are those generating units whose retirement/deactivation would result in violations of applicable reliability criteria unless appropriate transmission or resource reinforcements are forthcoming.

The Proposed Rule provides that existing generating units must come into compliance with the emission standards established under the Final Rule within 3 years from publication of the Final Rule in the Federal Register.[3] The Proposed Rule also allows extension of the compliance deadline by 1 year if an existing generating unit is going to install pollution controls to come into compliance with the standards. Finally, the Proposed Rule provides that if an existing generation unit retires rather than comes into compliance with the standards, and if replacement generation is being installed at the same location, such replacement generation can be considered in the same light as installing pollution controls and the same 1-year extension will apply (in other words, that retiring generator can remain in service for the additional 1 year without being held in non-compliance with the standards.)

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[1] U.S. Environmental Protection Agency National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial- Institutional, and Small Industrial- Commercial-Institutional Steam Generating Units, 79 Fed. Reg. 24976 (proposed May 3, 2011) (to be codified at 40 C.F.R. Pts. 60 & 63) ("Proposed Rule").
[2] 79 Fed. Reg. 25054.
[3] For purposes of these comments, we are assuming that date will be January 1, 2015. There is a discrepancy between the Proposed Rule and Section 112 of the Clean Air Act ("CAA") with respect to the point from which the compliance timeframe runs. That is, Section 112 of the CAA provides that compliance shall occur no later than 3 years from the effective date of the standard; whereas the Proposed Rule states that the compliance date is 3 years after publication in the Federal Register. PJM assumes that the compliance clock runs from the effective date of the Final Rule.

PJM's proposal is to allow the 1-year extension, and potentially a further extension beyond 1 year if necessary for reliability,[4] under the following circumstances:

(1) An asset owner provides notice to PJM and the EPA no later than the earlier of 12 months after the effective date of the Final Rule, or by January 1, 2013 that it intends to retire;

(2) PJM determines, through its public planning process, that the unit is a Reliability Critical Unit; and

(3) Transmission reinforcements or alternative resources in the form of replacement generation (not necessarily at the same site), dispatchable demand response or energy efficiency targeted to the affected locations are being installed to ensure continued compliance with applicable reliability criteria.

To support this limited extension, PJM shows in these Comments that the analysis of reliability impacts contained in the Proposed Rule, although helpful, does not take into account the full spectrum of reliability issues, including local reliability impacts, associated with plant retirement decisions made by asset owners in response to the Proposed Rule. Local reliability impacts, as described more fully herein, are those reliability impacts that occur in an area that typically does not have enough generation to serve its load and must import much of its electricity via transmission lines. Although PJM has not identified at this time near-term resource adequacy issues associated with this particular Proposed Rule, PJM is concerned about the local reliability impacts that may arise from any single or set of unit retirements. By limiting its reliability analysis to resource adequacy and a representation of transmission limited to transfers between regions, the Proposed Rule understates the impact of the Proposed Rule on system reliability.

Moreover, PJM details in its Comments concerns with certain of the Proposed Rule's findings and its analysis of the timing and feasibility of local transmission reinforcements, replacement generation or Demand Response/Energy Efficiency resources substituting for retiring generation. PJM details in these Comments the challenges it has experienced in securing adequate and timely transmission reinforcements to meet announced retirements.

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[4] Should such an extension be needed, the asset owner, relying on findings of PJM concerning reliability impacts and the need for alternative resources and/or transmission reinforcements, would work with EPA to identify a specific date when alternative resources and/or transmission reinforcements would be in place to address the pre-identified reliability need resulting from the retirement. Necessary reinforcements would be identified and reviewed in the RTO's FERC-approved public and transparent stakeholder process. The details of when the Reliability Critical Unit would be permitted to run and for what length of time should, by necessity, be addressed on a unit-specific case-by-case basis. PJM is seeking the recognition and establishment of such a process in the Final Rule, with its actual implementation details addressed on a case-by-case basis.

PJM believes its proposal, summarized above and detailed in Section VI of these Comments, offers a tangible solution that will accommodate Congress' mutual goals of ensuring a clean environment and continuing reliability of the bulk power grid.[5] A process such as the one proposed by PJM should be embedded in the Final Rule to provide a clearly defined means to address potential reliability challenges that may arise from implementation of the Proposed Rule. PJM's proposed process, which it urges to be incorporated in the Final Rule as a reliability safeguard, is based on PJM's experience in dealing with plant retirements in its footprint and the feasibility of timely installing adequate alternatives to maintain system reliability. In a broader sense, PJM's experiences cited below are based on its many years of planning for, and directing the operation of, the bulk power grid in the region it serves.

PJM wishes to make clear at the outset, that it is ***not*** seeking an overall blanket extension of the implementation of the Final Rule itself. Rather, PJM's proposal is grounded in providing limited, targeted and temporary relief from the compliance deadline in those defined instances where PJM would issue unit-specific findings of adverse reliability impacts in response to timely notices of retirement. Under PJM's proposal, PJM can analyze and direct necessary transmission upgrades to address system or local reliability issues that cannot be remedied within the compliance timeframe discussion in Section V.M. of the Proposed Rule in order to maintain reliability. In those limited situations, the "reliability safeguard extension" operates as a compliance "safe harbor" for Reliability Critical Units planning to deactivate – *so long as such unit provides what amounts to at least 2 years' notice of retirement* – and so long as an alternative resource is not available within the compliance period to address the reliability impact of the unit's retirement. The rule should equally apply to units seeking to retire which are Reliability Critical Units and units that are being retrofitted. In both cases, the compliance action (retrofit or retirement) will ensure the unit achieves the emission rate standards set forth in the Proposed Rule. Moreover, in both cases, capital investment is required (new transmission or replacement resources in the case of a retiring unit and a retrofit in the case of a unit continuing in service) to ensure emissions are reduced to ensure compliance with the rule and bulk power system reliability.

Moreover, the targeted remedy proposed by PJM herein will allow the Final Rule to into account and accommodate Congress's related goal of ensuring bulk system reliability as envisioned in Section 215 of the Federal Power Act.[6] The two goals must work in conjunction with each other rather than at cross-purposes. PJM's proposal accommodates that goal.

I. PJM's RESPONSIBILITIES AS AN RTO

FERC Order No. 2000 sets forth the specific characteristics and functional responsibilities of an RTO. These include:

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[5] Clean Air Act, 42 U.S.C. Sec. 7401, *et seq.*, (2010); Federal Power Act, 16 U.S.C. Sec. 824*o* (2010).
[6] 16. U.S.C. Section 824*o*.

- Short-term Reliability
- Operational Authority
- Planning and Expansion
- Congestion Management; and
- Interregional Coordination[7]

In order to be recognized as an RTO, FERC requires that the governance structure of the entity so requesting be entirely independent of asset owners and operators. Consistent with its RTO designation,[8] PJM's Board of Managers ("Board") is entirely independent of its market participants. As memorialized in PJM's governing documents such as the Operating Agreement, the Board's responsibility is to:

- Ensure reliable operation of the grid;
- Promote robust competitive wholesale markets; and
- Avoid undue influence by any market participant or group of market participants.[9]

A. PJM's Limited Authority Over Generation

Consistent with its duties as an RTO as spelled out in FERC Order No. 2000, PJM has registered with the North American Electric Reliability Corporation ("NERC") as, among other categories, the balancing authority and reliability coordinator for its 13-state footprint. In this role, PJM can direct actions to ensure that the generating units within its footprint are operated in a manner which meets approved reliability standards. However, it should be noted that the generators in PJM's footprint have largely been deregulated at the wholesale level as a result of FERC rulemakings and orders. Although PJM can direct certain actions be taken by generators to avert emergencies, it should be noted that PJM cannot direct the construction or operation of particular generating units nor require upgrades to those generation units. FERC has reaffirmed PJM's important but limited role by rejecting a PJM Open Access Transmission Tariff ("PJM Tariff" or "Tariff") proposal that would require a generator to continue operating by noting:

> we are rejecting the specific language . . . that provides that PJM can "require" generators to continue to operate for an indeterminate period, because PJM has not adequately shown that it has the authority to require generators to operate beyond a reasonable notice period.[10]

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[7] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) ("FERC Order No. 2000").
[8] PJM received RTO designation by FERC in 2001. *See PJM Interconnection, L.L.C., et al.*, 96 FERC ¶ 61,061 (2001).
[9] Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. at Section 7.
[10] *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 137 (2005).

As a result, the PJM Tariff currently requires only 90 day's notice of a generating unit's plan to retire prior to that unit formally retiring.[11] Within 30 days of the receipt of a generator's notice of deactivation under the PJM Tariff, PJM must inform the generator whether deactivating the generating unit would adversely affect the reliability of the transmission system.[12] Regardless of whether deactivating the generating unit would adversely affect the reliability of the transmission system, the generator may deactivate its generating unit, subject to the notice requirements in the PJM Tariff.[13] The costs of transmission upgrades are not bome by the retiring unit but instead are allocated to loads within PJM. In short, there is no "exit fee" associated with units retiring from service within the PJM footprint, nor does PJM have the legal authority to simply block an intended retirement.

By the same token, at least 8 of the states, as well the District of Columbia, in PJM's footprint have restructured their regulation of generation at the retail level. In certain states restructuring laws have limited the state's ability to direct upgrades or retirements to particular units.

B. <u>PJM Authority Over Transmission</u>

Because transmission remains a regulated asset, largely at the wholesale level, PJM has greater, albeit still limited, authority to order transmission upgrades. Specifically, transmission owners joining PJM are required to sign the Consolidated Transmission Owners Agreement. The Transmission Owners Agreement authorizes the PJM Board to direct transmission upgrades that the Board determines, consistent with the Operating Agreement, are needed to address either system wide or local reliability criteria violations. PJM exercises this authority through its open and transparent Regional Transmission Expansion Plan Process ("RTEPP").

II. ATTRIBUTES OF RELIABILITY

A. <u>Reliability Concepts and Local Reliability Defined</u>

Both NERC reliability standards, and the local reliability criteria, are intended to evaluate and ensure preservation of the electric reliability of the transmission system. As used by industry experts, the terms "electric reliability" or "reliability" refer to the delivery of electricity to customers in the amounts desired and within acceptable standards for frequency, duration and magnitude of outages and other adverse

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[11] PJM Tariff at Section 113.1. PJM is not unique among RTOs with respect to the notice requirement; with other RTOs' notice requirements generally ranging from 90-180 days.

[12] PJM Tariff at Section 113.2

[13] During that period, the generator can decide to remain in operation for the period that it takes to reinforce the system for the reliability impacts and either be paid under a Reliability Must Run agreement (designed to cover a unit's costs) or file with FERC for cost based rates; but the generator is not required to do so

conditions or events.[14] According to NERC, the industry has often defined "reliability" with two concepts: system security and resource adequacy.[15]

1. Attributes of System Security

System security, as it relates to reliability, is defined as the ability of the electric system to withstand sudden disturbances such as electric short circuit or unanticipated loss of some system component such as a line, transformer, or generating unit. The notion of system security comprises two elements: 1) transmission security; and 2) maintenance of sufficient ancillary services. Transmission security ensures that all transmission assets (lines and transformers) do not exceed their designed maximum loadings and that designated voltage levels are maintained in actual operation or in the case of a contingency.

Generation contributes to system security through 1) changes in the amount of generation that is dispatched to produce energy in real-time to meet load while respecting the physical limitations of the transmission system, and through 2) the provision of ancillary services that support the transmission of capacity and energy from generation to load while maintaining reliable operation of the transmission system.[16] Ancillary services such as Voltage and Reactive Power Support are necessary to maintain transmission system voltages within acceptable ranges.[17] Ancillary services such as Reserves,[18] Regulation and Frequency Response[19] and Black Start Service[20]

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[14] "Reliability standard" is defined as "a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity." 16 U.S.C. Section 824*o*(a)(3).
[15] *See* NERC FAQs which can be found at the following URL link: http://www.nerc.com/page.php?cid=1%7C7%7C114 .
[16] *See* NERC Glossary of Terms, http://www.nerc.com/files/Glossary_of_Terms_2011May24.pdf.
[17] Voltage and Reactive Power Support ("Voltage Support") supports power flows across the high voltage transmission system that allows power to be generated at one location and delivered to loads at another location often far from the generation source. It is essential to maintain voltages at prescribed levels to facilitate delivery of energy often across long distances.
[18] Reserves represent capacity on generating units that is available within a prescribed time frame in the event of a system contingency such as the loss of a transmission facility or a generator. Reserves allow the system to continue operating and delivering energy to load without any shedding of load and while maintaining transmission security. Moreover, there are locational requirements for Reserves in PJM so that power may be delivered even if something occurs in system operations affecting generation supply or transmission availability.
[19] Regulation and Frequency Response ("Regulation") ensures system frequency can be maintained at 60 Hertz (cycles per second) and balances out small changes in generation and demand that occur on a moment by moment basis. Failure to maintain the system frequency at 60 Hertz could lead to system instability, and deviations too far from the desired frequency can cause generating units to trip off-line and no longer be able to inject power into the grid leading to a potential system collapse. Regulation is primarily supplied by generating units that have the technological capability to respond to moment by moment changes in the supply and demand balance. Storage technologies such as batteries and flywheels, and demand resources are also eligible to provide Regulation in PJM, although these

also help with overall system security. Voltage Support and Black Start are location specific in nature, which leaves these services vulnerable when they are provided by a relatively small set of generators.

2. Attributes of Resource Adequacy

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. To achieve the goal of resource adequacy, PJM maintains an installed reserve margin in excess of the forecasted peak load that achieves a loss of load expectation of 1 day in 10 years. This loss of load expectation standard is consistent with that prescribed in the *ReliabilityFirst* Corporation ("RFC") standard for planning resource adequacy.[21] RFC is the FERC-approved regional reliability entity under NERC that oversees reliability matters in the PJM region.

The mechanism by which PJM maintains resource adequacy is the Reliability Pricing Model ("RPM" or "RPM Capacity Market"). The objective of the RPM Capacity Market is to commit the least-cost set of capacity resources, including generation, Demand Response and Energy Efficiency resources, to maintain the target installed reserve margin. The RPM Capacity Market also accounts for the deliverability of resources over the transmission system through the modeling of potentially binding major transmission constraints so that if more capacity is needed in a constrained region, it can be committed.

The RPM Capacity Market procures and commits the majority of capacity resources in an auction (known as the Base Residual Auction – "BRA")) three years in advance of the year in which those resources must be available (known as a "Delivery Year"). Further, three additional auctions (known as "Incremental Auctions") are conducted leading up to the Delivery Year, through which additional capacity can be committed if necessary to satisfy load growth exceeding the initial forecast. Buyers and Sellers are also permitted to change their capacity market positions during the Incremental Auctions.

The RPM Capacity Market clearing prices reflect both the capital cost to develop and maintain capacity resources and the physical limitations of the transmission system, including the ability to reliably deliver power to all areas of PJM. If the capital costs of capacity resources decrease, the price of capacity will also likely decrease, all else equal. It is possible for the cost to decrease to a point where the RPM Capacity Market

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resources account for only a tiny fraction of these 'regulating' resources. PJM operates a market for Regulation on an hourly basis in order to maintain sufficient resources to provide this service.

[20] Black Start Service refers to generation that can provide power to start other generation on the system to aid in system restoration. Black Start Service is location specific to meet the requirements to provide start-up power to generation at specific locations to aid in system restoration.

[21] RFC Standard BAL 502 RFC 02: Planning Resource Adequacy Analysis, Assessment and Documentation.

would commit capacity resources in excess of the installed reserve margin target if cost-effective to do so. Conversely, if the capital costs of capacity resources increase, as would be the case for resources requiring environmental retrofits under the instant Proposed Rule, the price of capacity likely will increase, all else equal, and fewer capacity resources will be committed; possibly at a level below the installed reserve margin. Finally, if it is necessary to commit resources in an area with major transmission constraints, prices in the constrained area will be higher than in other areas that are unconstrained.

3. Local Reliability

The two concepts of system security and resource adequacy also apply in locally constrained areas or so-called "load pockets." Load pockets are created when a major electric load center (*i.e.*, an area where there is a highly concentrated use of electricity such as the major urban centers along the east coast) has too little local generation relative to its load (likely due to difficulties of siting and building new generation in such areas) and must import much of its electricity via transmission lines.

Serving load pockets presents special reliability challenges related to system security. PJM as the transmission operator has to take steps to re-dispatch generation to avoid lines becoming overloaded in real-time operation. If generation resources that could otherwise be re-dispatched to maintain transmission security retires, in the longer term solutions such as transmission reinforcements will be necessary to prevent such overloads that can represent violations of FERC-approved reliability criteria. Importantly, these reliability challenges are not limited to the load pocket; they can adversely affect the areas surrounding the transmission facilities needed to carry that generation to the load pockets.

The presence of transmission constraints leading in to an area identified as a load pocket necessitates maintaining location-specific resources such as local generation to serve load in the load pocket under a variety of conditions. As mentioned above, certain ancillary services are location-specific by their nature and must function in close electrical proximity to where they are needed. As detailed below, it is these locational issues that need to be accounted for in EPA's Final Rule along with resource adequacy.

B. Ensuring Transmission Security: The Role of the Transmission Planning Process.

From a transmission planning perspective, transmission security ensures that during future forecasted peak system conditions, all identified violations of transmission reliability planning criteria are solved, including those related to thermal loadings, voltage levels and stability. In real-time operations, transmission security ensures that all transmission assets (lines and transformers) do not exceed their designed maximum loadings and that designated voltage levels in actual operation. Transmission security requirements also ensure that the bulk power system is resilient enough to withstand contingencies such as the loss of a line, tower or transformer while continuing to deliver energy and capacity from generation to load without interruption. In such situations, transmission security is maintained by operating transmission facilities with sufficient margin to take into account such contingencies. Failure to maintain adequate transmission security could result in the system operator invoking emergency operation procedures up to and including the shedding of load in a local area in order to prevent a cascading outage.

From a planning perspective, transmission security is maintained by proposing and directing the building of new transmission facilities, or transmission enhancements, to ensure energy is deliverable to load under forecasted peak conditions without violating reliability criteria, including that which governs acceptable thermal and voltage limits.[22] These peak conditions account for forecast changes in load levels and/or decreases in available generation in a constrained area that may be the cause of the need for a new transmission facility. Through its public planning process, PJM documents all conditions for which the system does not meet applicable reliability standards and identifies the system transmission reinforcements required to bring the system into compliance. The RTEPP also includes development of estimated costs and lead-times to implement upgrades needed to resolve identified reliability criteria violations. PJM experience in the RTEPP has shown that the inclusion or, more importantly for purposes of these Comments, exclusion of significant generation resources, particularly those in electrical proximity to constrained transmission facilities, can have a marked impact on the occurrence and timing of projected violations of NERC Reliability Standards. In short, the retirement of generation can, depending on the local circumstances, compel the need for significant transmission reinforcements.

III. THE EFFECTS OF RETIRING GENERATION ON LOCAL RELIABILITY

Changes in generation – and generating unit retirements in particular (referred to as retirements or deactivations interchangeably in these Comments)– alter power flow on transmission lines, transformers and circuit breakers; impact transmission system bus voltages potentially leaving fewer, or locally no generating resources to maintain transmission security. Additionally, generation deactivations or retirements leave potentially fewer resources to provide Ancillary Services such as Reserve, Regulation, and Black Start capability described above.

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[22] PJMs RTEPP validates compliance with NERC standards for Category A (TPL-001), Category B (TPL-002) and Category C (TPL-003) events for each year over a 15-year planning horizon. Specifically, NERC Reliability Standards require that a transmission system be stable and within applicable equipment thermal ratings and system voltage limits, as specified by PJM Operations. *See* PJM Manual M-3, accessible from PJM's website via the following URL link: http://www.pjm.com/~/media/documents/manuals/m03.ashx

A. Transmission Security Issues That May Result From Generation Retirement And Potential Solutions

The retirement of a generating unit may create transmission security problems in a local area absent any replacement resource in that location. Local transmission security issues may arise when a retiring generating unit causes changes in power flows during system peak load conditions that cause thermal and voltage limit violations.

Once PJM receives a deactivation request from a generator, PJM studies regional power flows based on forecast system conditions, including the system impacts caused by generator deactivation. Studies test the transmission system against mandatory NERC and RFC reliability standards, looking 15 years into the future to identify transmission overloads, voltage limitations and other reliability standards violations. PJM is required to develop and implement a solution for each identified violation which could otherwise lead to overloads, equipment failure, and in the most extreme circumstances a black-out.

In considering solutions for reliability violations, demand reduction initiatives such as Demand Response and Energy Efficiency are helpful tools, but unless the Demand Response and Energy Efficiency is committed in the RPM Capacity Market three years in advance, the Demand Response and Energy Efficiency is largely voluntary and, as a result, cannot guarantee the mitigation of the relevant reliability risks.[23] Demand Response located within the load pocket which make a financial commitment to PJM's capacity market through the RPM auctions can and does help ensure the need for adequate overall reserves in a given sub-region of PJM. However, even if Demand Response is being encouraged and new generation is being explored, construction of new or upgraded transmission lines is often essential to prevent imminent reliability problems from occurring while those alternatives are pursued and to account for the potential that those alternatives may not materialize in sufficient quantity to eliminate the reliability problem. As noted previously, PJM does not have the authority under any of its FERC-approved tariff documents to compel the construction of generation or procurement of Demand Response or Energy Efficiency. The availability of these resources remain the province of market forces.

At the most fundamental level, the need for solutions to reliability violations triggered by generation retirements stems from imbalances between the local generation resources and transmission capability to deliver energy and capacity from such resources. There may be multiple potential solutions to the reliability violations ranging from replacement generation, Demand Response or Energy Efficiency resources to transmission reinforcements. But given PJM's lack of authority to compel replacement generation or alternative resources such as Demand Response and Energy Efficiency resources, as explained above, transmission reinforcements -- developed to alleviate potential violations of voltage and thermal limits -- are the primary

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[23] PJM explains herein the requirements of its capacity procurement as it affects both retiring generation and demand response/energy efficiency resources.

direct solution available to PJM to address local reliability problems caused by generation retirements.

B. Challenges of Generator Deactivation on the Provision of Critical Ancillary Services

As previously mentioned, generation is often relied upon to provide critical Ancillary Services, such as Voltage Support and Black Start Service to ensure system security. When such a unit retires, there can be a negative impact on system security. Addressing these impacts can be difficult, given the location-specific nature of the services such units provide, as described herein.

"Voltage" is a measurement of the potential for an electric field to cause an electric current in a conductor; it is essentially analogous to pressure in a fluid. Voltage can be described as a "carrier" of electric energy. Voltage stability is important for a number of reasons. For instance, on the transmission system itself, transmission voltages must be maintained within specific tolerances to ensure that voltage-sensitive equipment operates properly. Most often, Voltage Support is provided by location-specific generation and thus can be impacted due to retirements, particularly of those older plants in urban areas where it is difficult to site and install new generation.

Black Start service, whether provided directly by small diesel or natural gas combustion turbines, or indirectly by larger units through "automatic load rejection,"[24] is also a service that is location specific. Transmission owners require Black Start Service at specific locations with the purpose of providing start-up power to generating units specified as part of the transmission owner's restoration plan should there be a blackout on that part of the power system. In the event a generator that provides Black Start Service is retiring, PJM must issue a request for proposal process to secure replacement Black Start capability. Replacing Black Start capability can take in the range of 6-36 months, depending on whether an existing unit will agree to replace the service or if new generation needs to be constructed.

C. Drivers for Generator Deactivation and Implications for Resource Adequacy

In a wholesale electricity market such as in PJM, generating units will only retire when generation asset owners believe the costs of continuing to operate, including the costs of environmental retrofits and desired returns on capital, exceeds the expected revenues from PJM's markets. To the extent the installation of environmental retrofits is costly and the generator does not expect to receive sufficient revenue from the markets, resources adequacy will not be impaired if there are sufficient capacity resources to meet the installed reserve margin targets.

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[24] "Automatic load rejection allows a generating unit to separate from the grid in the case of a major disturbance and operate in isolation until it can be reconnected to the grid to supply start-up power to other resources.

In the alternative, if insufficient resources are available at a lower cost, and the generating unit with high retrofits costs clears in the RPM Capacity Market, PJM will commit that unit's capacity, albeit at a higher price of capacity, such that the cost of maintaining resource adequacy will rise in the face of the impending environmental rules.

Finally, if the costs of environmental retrofits are sufficiently high for a large number of generating units, and there are not sufficient lower cost resources available to replace this capacity, capacity prices will rise to such a point that it will be considered cost-effective in the RPM Capacity Market to commit capacity at levels below the installed reserve margin thereby reducing resource adequacy reliability below the target 1-day-in-10-year threshold. This condition cannot be sustained indefinitely. The PJM Reliability Backstop mechanisms intended to guarantee that sufficient generation, transmission and Demand Response solutions will be available to preserve system reliability, is triggered by reliability criteria violations caused by: (a) lack of sufficient capacity committed through the RPM Capacity Market; or (b) near-term transmission deliverability violations identified after the Base Residual Auction is conducted.[25]

Transmission upgrades – new transformers, circuit breaker replacements, and line re-conductoring, for example – often can be put in place to address local reliability criteria violations, given sufficient procurement and construction lead time. In still other deactivation cases, new transmission facilities or upgrades to existing facilities can be installed to address thermal problems; and, reactive devices such as capacitors or static VAR compensators can be installed to address voltage problems on the system. However, these types of upgrades may require more than 90 days, the shortest advance notice PJM could receive for a retirement. Sufficient lead time is required to engineer the appropriate solution, procure equipment and complete all necessary construction. The time required to implement a transmission solution can vary considerably based on the size and complexity of the upgrade. Incremental upgrades to existing facilities can often be timely completed, particularly if no additional siting certifications are required. Upgrades such as new transmission lines that may require siting approval almost certainly take longer – often considerably longer.[26]

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[25] The Reliability Backstop may be found in Section 16 of Attachment DD of the PJM Tariff.

[26] For example, the construction of the Susquehanna-Roseland line is currently being delayed due to by federal agency environmental impact review. The need for this backbone transmission line was first identified by PJM and approved by the Board as part of 2007 RTEPP. At that time, the line was anticipated to be in service for 6/1/2012 to avoid identified reliability criteria violations. However, delays due to National Park Service review have delayed the in-service date of this line to 2015 at the earliest. *See* http://pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx Similarly, the retirement by Exelon Generation of the Cromby Unit 2 and Eddystone Unit 2 requires 18 separate transmission system enhancements to address the identified thermal, voltage and short circuit violations. Thus, even though Cromby and Eddystone provided notice of deactivation in December, 2009, due to the need for such transmission enhancements the units are not actually going to shut down until May, 2012. In the interim, their operation is environmentally limited. *See* http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx

IV. SPECIFIC COMMENTS ON EPA'S RELIABILITY ANALYSIS

In conjunction with the issuance of the Proposed Rule, the EPA also issued a ten- page resource adequacy and reliability analysis that indicates there are no resource adequacy or reliability problems with the implementation of the Proposed Rule. While PJM appreciates the EPA's recognition that resource adequacy and reliability are potentially a concern under this Proposed Rule, the analysis falls short in providing the detailed and rigorous examination of reliability as PJM has described in the previous sections, especially as applied to local reliability issues.[27]

The insufficiency of the EPA resource adequacy and reliability analysis stems from three major assumptions that do not match the realities faced by RTOs like PJM and its wholesale market participants. Specifically, the EPA analysis erroneously assumes: 1) wholesale power markets mirror least-cost planning models; 2) reliability is related to only movements of power between large geographic areas; and 3) there are no transmission or deliverability constraints within those areas.

The reliance on such assumptions, while making a nationwide analysis of broad resource adequacy and reliability trends, tractable from a computational and data input perspective, lead to conclusions regarding resource adequacy and operating reliability that do not match up with the experience of RTOs and generation asset owners. Specifically EPA's conclusions do not necessarily match with the potential level of retirements that the PJM region may see as evidenced by approximately 7,350 MW of coal-fired generation installed capacity, that have failed to clear the three year forward RPM Capacity Market auction for the 2014/2015 Delivery Year. PJM has released analyses of its most recent three year auction results which indicates that the failure of many of these coal units to clear on a three year forward basis appears to be largely attributable to their estimation of the costs of retrofitting these older units.[28]

PJM does not claim, at this early stage when the final EPA rules are still unknown, to know the exact amount of generation, let alone the location of generation, that will retire. Indeed, this uncertainty (and the lead time associated with planning,

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[27] The Proposed Rule does recognize that the analysis was undertaken on a macro-level and does not address these local reliability issues. However, as PJM details herein, these local reliability issues and, in particular, the ability to provide ancillary services such as Black Start and Voltage Support, can be exacerbated if there are significant generation retirements. Additionally, ICF International recently released a paper entitled *Retiring Coal Plants While Protecting System Reliability*, wherein ICF International reported the results of its analyses of the Proposed Rule's impact on transmission security stating, "The results of ICF International's analyses suggest that the location of the power plants being taken offline can significantly impact system reliability . . . ." http://www.icfi.com/insights/white-papers/2011/retiring-coal-plants-while-protecting-system-reliability

[28] *See* 2014-2015 Reliability Pricing Model Base Residual Auction Report Addendum, http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-rpm-bra-results-report-addendum.ashx. There was 6,895 MW of Unforced Capacity that did not clear tha auction. This figure accounts for the forced outage rate of the units in question. As an estimate of installed capacity, dived that figure by one minus the forced outage rate to get 7350 MW.

siting and constructing replacement transmission) is precisely why PJM seeks the two year advanced notice of retirement set forth in Section VI of these Comments. As noted herein, although PJM believes the EPA analysis contains some erroneous assumptions that lead to an understatement of the level of retirements, PJM does not, based on its preliminary analysis, forecast a *capacity* shortfall in the region at this time. However, PJM does anticipate that local reliability problems could well arise as a result of these retirements which would require upgrades, some of which may not be in place by the time for compliance with the Final Rule.

PJM addresses each of the aforementioned issues in turn below beginning with wholesale market assumptions, moving to reliability assumptions, and finally concluding with experience, analysis, and empirical results to date regarding coal generation retirements and the need for transmission upgrades due to generation retirements.

A. Wholesale Market Assumptions

As explained above, in a wholesale electricity market context such as in PJM, existing generating units, regardless of technology and fuel type, will factor into their decision to retire or deactivate whether expected revenues from PJM markets exceed costs of continuing operation. including the costs of environmental retrofits . Conversely, new entry of generation resources, Demand Response or Energy Efficiency is expected to occur in wholesale markets when the expected return on that investment exceeds the desired return on capital. The key, underlying feature of wholesale markets for energy and capacity is that these ***retirement and new entry decisions are made in a decentralized manner based on price signals that are provided by these markets*** that signal the financial profitability of existing and new entry resources. Moreover, these decisions are based on individual generation asset owner's expectations of the future which may differ significantly from one owner to the next, and from one unit to the next.

In contrast, the Integrated Planning Model ("IPM") employed by the EPA in its resource adequacy and reliability analysis does not reflect the manner in which decisions are made in the wholesale market. The objective of the IPM is to minimize the system-wide, region-wide, or nation-wide cost of achieving resource adequacy and maintaining its representation of transmission reliability subject to the environmental constraints imposed on generating units by the Proposed Rule. In sharp contrast to market dynamics, in the IPM modeling framework employed by EPA, the retirement and new entry decisions are centralized; the decisions, are not based on market price signals and do not depend upon unit profitability or returns on investment. Rather, the decisions are based on cost and perfect foresight of future market conditions. As a consequence, the IPM model may reflect retirement and new entry decisions that differ significantly from the actual market-based retirement and new entry decisions.

Wholesale energy and capacity markets in PJM also allow for the participation of Demand Response and Energy Efficiency, and are of particular relevance in the RPM Capacity Market. In many cases these resources are lower cost capacity alternatives than traditional generation resources and can have an effect on market prices and ultimately on the retirement and new entry decisions of generation resources when considered in conjunction with the costs imposed by the Proposed Rule.

The IPM framework does not account for Demand Response and Energy Efficiency resources as new capacity entry, nor does it account for the effect these resources may have on market prices that drive retirement and new entry decisions. And, consequently, even under the centralized decision making of cost minimization, the IPM framework is likely missing possible generation retirements that may be driven by the interaction of the Proposed Rule with these potentially lower cost capacity resources. This is not to say that Demand Response and Energy Efficiency do not provide significant benefits and could, in the right circumstances, reduce overall compliance costs and fully substitute for that retired generation as capacity resources. However, on a location-specific basis, Demand Response and Energy Efficiency may not be a complete substitute for certain of the ancillary services outlined above. As a result, an effective compliance strategy requires the examination and integration of all of these resources and adequate time to ensure there effective implementation.

In short, the IPM framework for examining the effects of the Proposed Rule on generation retirements (particularly coal) does not match up with the manner in which decisions are made nor does it recognize the full range of the possible resources available in the market. Therefore, the IPM framework is likely to understate the magnitude of coal generation retirements. This in turn may understate the volume of system security and local reliability issues faced by RTOs and other transmission operators.

B. Reliability is More Than Moving Power between Large Geographic Regions

As PJM has stated above, an analysis of system security requires a more granular review of the ability to ensure transmission security in load pockets. It is not sufficient to assume that because the region as a whole has sufficient resources, that local reliability is automatically maintained, as is the assumption made in the IPM framework. With respect to transmission alone, the IPM framework omits key features of the bulk power transmission system that lie within the IPM-defined regions. First, the IPM modeling of regions misses large 500 kilovolt ("kV") reactive transfer interfaces that reside within some of the regions.[29] Second, some of the regions span across multiple RTOs which would neglect to account for the fact that each RTO region undertakes its own security constrained generation dispatch.[30] Third, the manner in which power is moved from one region to another in IPM does not account for parallel path or loop flows that occur across multiple regions and the international border between the US

[29] For example, in the MAACW region, there are three 500 kV reactive transfer interfaces, Western Interface, Central interface, and the 5004-5005 interface.
[30] The RFCO region defined in IPM includes both PJM and MISO transmission systems.

and Canada that take careful inter-regional coordination between multiple RTOs and transmission providers to solve.

As has been documented by the Independent Market Monitor ("IMM") for PJM in its recent State of the Market Report, the amount of generation available to be re-dispatched to alleviate localized constraints to maintain transmission security in these areas is small, sometimes only one or two generating units have the ability to relieve such localized constraints.[31] As the work from the IMM clearly shows, the deactivation or retirement of some generation would take away potential re-dispatch solutions and therefore likely trigger the need for transmission upgrades to prevent transmission reliability criteria violations. The possibility of generation deactivations or retirements triggering transmission upgrades can be easily seen by examining the history of generator deactivations in PJM as well as pending deactivations. The lists of historic and pending deactivations are publicly available and show that of all the pending deactivations, more than half require transmission upgrades to allow the unit to retire without a violation of transmission reliability criteria.[32] In the case of the Benning Road and Buzzard Point units, which are in Washington, D.C. -- a locationally-constrained area -- the transmission reinforcements necessary to mitigate the reliability impacts of such retirement are scheduled to take more than 5 years to place in service.[33]

At this time, there are only 3,262 MW of all generation types with requests for deactivation pending. Most of these require the installation of some type of transmission upgrade to allow those units to retire without any transmission reliability criteria violations. If there are considerable coal generator deactivations as a result of the Proposed Rule, there is a high probability that many of these units can only be reliably retired once transmission upgrades are placed into service. Moreover, if the sheer volume of retirements is large, in contrast to the results reported by EPA in its analysis, there may be a deleterious effect on local transmission reliability resulting from the set of collective retirements; impacts that may not have been triggered with only a small set of unit retirements. As noted below, given the limited time period for notice of deactivation and the uncertainty concerning the contents and effective date of the Final Rule, generation owners have been reluctant to announce firm plant retirement decisions. This delay then further complicates decisions by PJM to plan and direct installation of the appropriate set of transmission upgrades.

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[31] *See, e.g.*, Section 7 p.483 Table 7-5 Congestion summary (By facility type): Calendar year 2010. The 2010 State of the Market report prepared by the IMM in the PJM region, Monitoring Analytics, can be found at the following link:
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume2.pdf

[32] *See* http://pjm.com/planning/generation-retirements.aspx. There are other deactivation requests that would have resulted in even more transmission reliability violations but for previously approved RTEPP upgrades that are scheduled to go into service by the time the units will deactivate.

[33] See the deactivation study related to the Benning Road and Buzzard Point units at the following URL: http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/20070531-buzzard-evaluation.ashx

C. Concerns with EPA's Analysis of the Breadth of Generating Unit Retirements in PJM

In its resource adequacy and reliability analysis, EPA has estimated that at most only 1,090 MW of coal capacity will retire by 2015 in the PJM region with the implementation of the Proposed Rule.[34] With such a low estimate of retiring coal capacity, the probability of local reliability issues – if the EPA had analyzed such issues – would also be potentially much smaller so that the assumption of deliverability of energy within any of the IPM-defined regions would not appear to be so critical.

The reality regarding the magnitude of coal capacity retirements, however, may well be quite different based on market indicators to date. One indication of the ability of any type of generating capacity to be financially viable moving forward is whether or not it has cleared (been committed) in PJM's RPM Capacity Market auctions. Environmentally-challenged capacity that does not consistently clear in the three-year ahead Base Residual Auction is not likely to continue in service since capacity market revenues are such an important source of revenues for these units as they determine whether or not to retrofit.[35] PJM already knows that as a result of the 2014/2015 RPM Base Residual Auction there was approximately 7,350 MW less coal-fired generation that cleared than in the previous 2013/2014 Base Residual Auction. In other words, there are strong indications, based on their economic position that approximately 7,350 MW of installed coal-fired capacity could retire if this trend continues. This is almost seven times that amount of capacity that EPA estimated would retire in response to the Proposed Rule.

In addition to coal-fired capacity that did not clear in the 2014/2015 BRA, there is also coal-fired capacity in PJM that serves as Capacity Resources designated through the Fixed Resource Requirement ("FRR") option that allows load serving entities to satisfy their capacity obligations outside of the RPM Capacity Market framework. This capacity is located in the areas served by American Electric Power and public power entities within the American Electric Power transmission zone. To date there have been public announcements of approximately 7,000 MW of installed coal-fired capacity that have been announced for retirement by FRR entities for the 2014/2015 delivery year in PJM due to the Proposed Rule.[36]

Between the reduction in cleared coal-fired capacity in the last Base Residual Auction and the public announcements by FRR entities, there is just over 14,000 MW of

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[34] In fact, this is likely an overestimate since there is overlap between PJM and MISO in one of the IPM defined regions.

[35] Under PJM's RPM rules, units are required to offer into the RPM auction with only very limited exceptions.

[36] AEP plans to retire approximately 6,000 MW of coal-fired generation: AEP Press Release June 9, 2011, Duke Energy plans to retire approximately 1,000 MW of coal-fired generation: Duke Energy Press Release July 15, 2011. Duke Energy Ohio and Duke Energy Kentucky are scheduled to integrate into PJM on January 1, 2012..http://www.aep.com/environmental/news/?id=1697, http://www.duke-energy.com/news/releases/2011071501.asp

coal fired capacity at risk for retirement by 2015 due to the cumulative effect of various EPA proposed rulemakings including the subject Proposed Rule, as well as due to economics. What remains unknown is the extent to which, based on today's capacity prices, new, cleaner generation comes on line 2014/2015 RPM BRA delivery year and the extent that new DR and EE resources both develop and commit to serve as capacity resources in the RPM Capacity Markets.

PJM's preliminary analysis of potential coal-fired generator retirements identifies approximately 20,000 MW of coal-fired capacity less than 400 MW in the PJM region that is more than 40 years old and that will require some kind of environmental retrofit to continue forward.[37] Because such units are small and old, they are likely already not very efficient and do not operate as often as larger and more recent vintage coal units, so these smaller, older units are likely candidates for retirement.

This analysis further indicates that PJM's system includes at least 11,000 MW of coal-fired capacity where the estimated cost to install the necessary retrofits will exceed the present projection of building a new efficient unit (known as the Net Cost of New Entry or "Net CONE"). Net CONE is a value that reflects the nominal levelized cost to build a new natural gas fired combustion turbine. Because it would be less costly to build a new natural gas fired combustion turbine than retrofit these units, this capacity appears not competitive with new entry resources and thus may be at greatest risk for retirement. [38]

Additionally, PJM has identified another 14,000 MW of coal-fired capacity where the estimated costs of required retrofits fall between one-half the Net CONE and Net CONE. These units may be financially viable to continue forward with retrofits, but it is difficult to assess the risk of retirement from this group as such decisions will be influenced by other factors and information that is unique to each generation owner, and to which PJM does not have access.

The empirical evidence of apparent and likely retirements and PJM's own analysis points to a volume of potential retirements that could well be more than 10 times the amount of capacity that the EPA has estimated in response to the Proposed Rule. PJM is not saying that retirement of aging costly generation is on its face a negative---overall, it is not. However, given the magnitude and timing of this level of retiring generation, PJM estimates that a number of local reliability issues not identified in EPA's analysis will occur which will require transmission upgrades or other solutions. This magnitude and timing of potential retirements is unprecedented in the PJM region. The full effects will not be known until the full set of unit retirements is announced so that PJM can conduct the necessary studies to determine the extent of the local

[37] PJM will be posting the results of its analysis, once available, on its website at www.pjm.com.
[38] The economic analysis only examines generation in PJM prior to the ATSI and DEOK integrations as PJM does not have sufficient historic revenue information for these units to do an accurate assessment of their financial viability to continue forward with retrofits.

reliability problems and identify the potential transmission solutions. However, the prospect of a number of retiring units, the insufficient forward notice of retirement as explained in Section I.A. above, and the prospect of PJM not being able to ensure that the necessary transmission upgrades or replacement resources can all be placed into service within the timeframe of the Proposed Rule compels PJM to recommend its unit-specific reliability safeguard process outlined in Section VI below.

D. Preliminary Observation: Resource Adequacy and System Security

Even with as much as 11,000 to 14,000 MW of coal-fired capacity at risk for retirement, resource adequacy (*i.e.,* the overall level of capacity needed to serve the RTO's needs) does not seem to be immediately at risk. First, for the 2014/2015 delivery year with approximately 7,350 of coal-fired installed capacity not clearing, PJM projects a 19.6 percent installed reserve margin which is approximately 6,400 MW of installed capacity over and above the target installed reserve margin.[39] The primary reason for this is that the demand forecast has fallen and Demand Response resources have made up the difference. Even accounting for the retirement announcements of FRR entities and announced new generation plans, there do not presently appear to be significant issues in maintaining capacity levels at the installed reserve margin in the short term.[40] In the 2014/2015 Base Residual Auction there was an increase of 4,800 MW of Demand Response resources over the previous auction. If that trend continues and combined with the potential development of new generation as evidenced by PJM's generation interconnection queue, there appear to be adequate reserves assuming new generation can be attracted, sited, and built in a timely manner. However, as explained above, resource adequacy and operating reliability, *i.e.,* system security, are very different issues, and the sheer volume of retirements and associated local reliability problems are the main near-term issue as the compliance deadline of January 1, 2015 approaches.

V. SPECIFIC COMMENTS ON THE PROPOSED RULE'S FINDINGS REGARDING ADDRESSING RELIABILITY IMPACTS

In this section, PJM provides specific comments to certain of the EPA's factual findings in Section V.M. of the Notice that are cited in support of the overall finding that the Proposed Rule will not adversely impact reliability. PJM recognizes that the provisions of Clean Air Act section 112 limit EPA's ability to provide blanket extensions beyond the three year schedule (with an additional one year extension for the installation of controls) ("the 3+1 schedule"). In PJM's proposed remedy, contained in Section VI below, PJM sets forth its specific proposal, which is entirely consistent with Clean Air Act section 112. PJM's proposed remedy represents the best means to

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[39] 2014-2015 Reliability Pricing Model Base Residual Auction Results Report at 1, http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx.

[40] The approximate cushion covers the announced retirements and Duke Energy Ohio and Kentucky, which will integrate into PJM in January 2012, has announced new build gas with their retirements

harmonize the Final Rule with Congress' directives to ensure the maintenance of reliability of the bulk power electric grid while achieving its Clean Air Act directives.

Each relevant EPA finding is reprinted with PJM's comment immediately below that reprint.

EPA Finding Para. M, Federal Register p. 25054:

"CAA section 112 specifies the dates by which affected sources must comply with the emissions standards. Existing sources may be provided up to 3 years to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case by case basis, if such additional time is necessary for the installation of controls. We believe that the requirements of the proposed rule can be met without adversely impacting electric reliability. Our analysis shows that the expected number of retirements is less than many have predicted and that these can be managed with existing tools and processes for ensuring continued grid reliability."

PJM Comment:

PJM has pointed out above the limitations of the reliability modeling presented by EPA. PJM does not posit that, as a result of those limitations, the impacts set forth by EPA are *per se* incorrect----rather, given the fact that the full impact of the Proposed Rule and the resulting generator decisions on whether to comply or retire have not been made, it is simply premature to reach a definitive conclusion that, in all cases, "*the proposed rule can be met without adversely impacting electric reliability*[41]." As noted above, there are many aspects of reliability -- ranging from overall capacity adequacy in an entire region to local reliability impacts from plant retirements -- which require much more specific analysis than has been able to be performed to date. Moreover, although EPA's analysis addresses overall system adequacy, a second critical aspect of reliability, namely system security, has not been analyzed under the Proposed Rule.

PJM does not make this observation as a blanket criticism of EPA's analysis. Rather, PJM points out that the information needed to undertake this more granular analysis cannot be meaningfully performed until further information is known as to individual unit's retirement decisions.[42] As a result, PJM believes that the EPA's findings as quoted above are sweeping and summary in nature and thus EPA would have difficulty meeting the reasoned-decision making standard for judicial review.

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[41] Proposed Rule at 25054.

[42] In Section VI below, PJM proposes a remedy to this "chicken and egg" problem by seeking a requirement for early and timely notification to EPA and the RTO of individual unit's plans to comply or retire.

EPA Finding Para. M, Federal Register p. 25054:

"There are already tools in place (such as integrated resource planning, and in some cases, advanced auctions for capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as the proposed rule."

PJM Comment:

As noted above, generation adequacy has largely been deregulated at the wholesale level. In many cases, as the Tariff provides, PJM receives only 90 days notice of retirements and FERC has affirmed that PJM has no ability to stop a unit from retiring.[43] Moreover, most of the states in the PJM footprint do not have authority to develop and, more importantly, order the results of state-developed integrated resource plans ("IRP").[44] For instance, it is PJM's understanding that IRP is not utilized across the entire PJM footprint in the manner EPA assumed in its analysis. Several states in PJM rely on competitive markets for utility procurement of generation supply to serve customers not served by competitive retail suppliers. As a result, EPA's reliance on integrated resource planning as a "*tool in place that ensures that companies adequately plan for, and markets are responsive to, future retirements such as the proposed rule*" is inconsistent with the law and/or policies of a number of the state commissions within the PJM footprint and therefore cannot be relied upon as a justification for the 3+1 deadline.

The Notice also references "*advanced auctions for capacity*" as another means to "*ensure that companies adequately plan for, and markets are responsive to, future requirements such as the proposed rule*". In the case of PJM, the EPA is correct in referencing the fact that PJM runs a three-year forward auction for capacity – RPM. RPM acquires resources for capacity three years into the future. While this auction addresses the resource adequacy aspect of reliability in PJM, it does not necessarily focus on the local transmission security within Locational Deliverability Areas ("LDAs"). The three year forward auction does force a unit to determine its compliance strategy in a timely maner as it is required to either bid in the unit (and thus legally be obligated to PJM to be able to be called on to supply energy three years forward) or not submit a bid based on its decision to retire the unit. A unit could enter into the RPM auction each year with the intent to retrofit but then end up not clearing and ultimately retiring once it weighs the cost of retrofits vs. the forward capacity price it would have received had it cleared in the PJM capacity market along with energy market revenues it might have earned. Additionally, a unit that clears the auction and later decides to retire can either pay a penalty or contract for replacement capacity, both options of which may be more economical than the cost to keep the unit running to meet its obligations. As such, PJM's forward capacity market, although a helpful tool, cannot, in and of itself, ensure that the effects of the rule are fully dealt with in the marketplace with sufficient advanced notice to address the development of alternatives. Moreover, in some cases retrofits may need more than three years for completion. In short, the limited three year forward

[43] *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 137 (2005).
[44] *Nantahala Power & Light v. Thornburg*, 476 U.S. 953 (1986).

capacity market is a helpful but not dispositive tool to allow the market to respond to the impact of the Proposed Rule.

EPA Finding Para. M, Federal Register p. 25054:

"EPA believes that the ability of permitting authorities to provide an additional 1 year beyond the 3-year compliance time-frame as specified in CAA section 112, along with other compliance tools, ensures that the emissions reductions and health benefits required by the CAA can be achieved while safeguarding completely against any risk of adverse impacts on electric system reliability."

PJM Comment:

PJM believes that there is no record basis for EPA's sweeping conclusion that the 3+1 compliance period in the Proposed Rule *"safeguards completely"* against any adverse impacts on electric system reliability. As noted previously, the local reliability impacts of the Proposed Rule are unknown and the larger regional adequacy impacts can only be determined once the impact of the Final Rule has been analyzed and units have made their individual retrofit vs. retirement decisions. PJM's preliminary analysis as described above indicates that the number and size of retirements in EPA's analysis is significantly understated.

PJM appreciates the EPA's recognition of the concern and has proposed a reliability safeguard as set forth in Section VI below. PJM believes that adoption of this safeguard proposal is necessary to meet the rule's goal of *"safeguarding completely against any risk of adverse impacts on electric system reliability."* Without such a backstop, PJM believes there is inadequate record support for the finding and more importantly, the potential that the Proposed Rule could damage rather than *"safeguard completely"* electric system reliability.

EPA Finding Para. M, Federal Register p. 25054:

"Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained. EPA also intends to continue to work with DOE, FERC, state PUCs, RTOs and power companies as this rule is implemented to identify and address any challenges to ensuring that both the requirements of the CAA and the need for a reliability electric system are met."

PJM Comment:

PJM appreciates EPA's acknowledgment and invitation to work with the agency on ensuring that the Final Rule meets the dual goals of Clean Air Act compliance and ensuring electric system reliability. PJM does believe that certain policy initiatives can be implemented amongst the agencies to help ensure compliance and reliability. These include the EPA incorporating into the Final Rule the Secretary of Energy's authority under section 202c and ensuring that his exercise of authority, after coordination with EPA, does not leave a complying entity subject to penalties from either state officials or citizen lawsuits under the Clean Air Act.

PJM further urges the EPA to work with RTOs ***prior to*** the Final Rule going into effect so that the proposals presented herein and similar ones can be addressed in a manner which ensures that the Final Rule does not impair reliability. PJM believes that it is critical that appropriate safeguards and backstops be included in the Proposed Rule rather than having the EPA wait to work with the RTOs on such measure only until after the rule's final issuance. For its part, PJM stands ready to work with EPA, FERC, the State air authorities and others to ensure that any Final Rule can be implemented in a manner that is cognizant of the critical need to ensure maintenance of bulk power reliability during this period.

PJM also urges the EPA to work with State air authorities as the environmental permitting entities, to implement compliance schedules for individual facilities where appropriate to maintain electric system reliability.

<u>EPA Finding Para. M, Federal Register p. 25055:</u>

"*(T)he additional 1-year extension would provide an additional two shoulder periods to schedule outages. It also provides additional opportunity to spread complex outages over multiple outage periods. EPA believes that while many units will be able to fully comply within 3 years, the 4th year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary.*"

<u>PJM Comment:</u>

PJM has the authority to approve all unit scheduled outages to ensure that such outages do not adversely impact reliability, but cannot prevent generators from taking outages when they believe they need to tie in pollution control retrofits. PJM appreciates EPA's recognition of the need to spread complex outages over multiple outage periods. As the breadth of the outages and the availability of retrofit materials may impact the scheduling of outages, it is not clear that the proposed 3+1 timeline provides sufficient flexibility for PJM to manage all of these outages in a staggered manner.

For instance, once the need for transmission upgrades have been identified to permit the safe deactivation of a given generator, PJM's Tariff requires that Transmission Owners and Interconnection Customers coordinate all transmission system outages with PJM to permit those upgrades to be constructed, in accordance with the PJM System Operations outage planning procedures.

In short, outage windows to accommodate upgrade construction are limited to opportunities when prevailing system conditions permit so that operational reliability is not compromised.

Transmission Owners provide notice of planned outages to PJM in accordance with the requirements in the PJM Tariff and, if applicable, under the TOA. Required notice is defined as (1) notification of planned outage schedules six months in advance for transmission outages which are expected to exceed five days, and (2) notification of all transmission outages five working days or less by the first day of the month proceeding the month of the outage.

Under certain conditions such as extreme weather, peak load, heightened homeland security, *etc.*, PJM will evaluate the need to operate the grid in a more conservative manner. Actions that may be taken in these special circumstances include, but are not limited to, canceling or rescheduling outages and returning outaged equipment to service.

Moreover, Transmission Owners are to avoid scheduling any outage in excess of 5 days in duration with no or greater than 5 day restoration time that may result in increased risk to system reliability during peak summer and winter periods. These periods are defined as June 15 – August 31 and January 1 – February 28, respectively. These outages include those that may result in:

- Actual or post-contingency thermal or voltage issues with insufficient generation for control
- Constraints that are load sensitive with limited controlling actions
- Stability issues or bottled generation

Transmission Owners screen for such outages prior to submittal and look to reschedule during shoulder months. PJM also screens for such outages when performing outage analysis. Transmission Owners are encouraged to schedule non-impactful outages during peak seasons.

Thus, given the details around PJM's FERC-approved outage process, this is an issue which requires timely and early notice from unit owners and a willingness of EPA to potentially extend the compliance deadlines to accommodate challenges in scheduling outages while still maintaining system reliability. PJM's proposed remedy outlined in Section VI below is thus a vital component to ensuring that EPA's observations concerning the importance of staggering complex outages can actually be effectuated in a manner which ensures system reliability.

EPA Finding Para. M, Federal Register p. 25055:

"EPA believes that it is reasonable to allow the (one year) extension to apply to the replacement (of existing units) because EPA believes that building of replacement power could be considered "installation of controls" at the facility."

PJM Comment:

PJM supports EPA's reading of the statute to allow the additional one year for compliance when there will be installation of replacement power – which is viewed as equivalent to installing pollution controls -- at the site of a where a generating unit is being retired. Such a reading works to effectuate the ability of owner's to install, within a four year period, cleaner replacement generation in lieu of being forced to retrofit units which are most likely near the end of their useful lives. Moreover, the availability of a new unit may prove far more reliable than attempting to retrofit units which already are at the end of their useful lives. This same rationale should apply to a situation where the additional one year (or longer) is needed to install replacement generation or DR and EE at another location; as well as when a transmission reinforcement is needed to mitigate the reliability impacts of a retiring generating unit.

EPA Finding Para. M, Federal Register p. 25055:

"Reliability concerns caused by local transmission constraints can be addressed through a range of solutions...For instance, in the PJM Interconnection (an RTO) region, there are over 11,600 MW of capacity that have completed feasibility and impact studies that could be on-line by the third quarter of 2014."

PJM Comment:

As a basis for its finding, the Proposed Rule cites to a presentation made by PJM in January, 2011. While the relevant presentation did state amount of proposed generation in PJM's interconnection queue, this was in regards to addressing the resource adequacy aspect of reliability, and not necessarily the transmission security or local reliability aspect. So, while these resources provide the needed system capacity, it will not be known until local transmission constraints arise and are studied if these resources can address local issues.

EPA Finding Para. M, Federal Register p. 25055:

"These type of resources (Demand Side response and energy efficiency) can be developed very quickly. In 2006, PJM Interconnection had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity. "

PJM Comment:

It is true that Demand Response and Energy Efficiency can provide significant benefits and can, in the right circumstances, reduce overall compliance costs, on a location-specific basis. However, Demand Response and Energy Efficiency may not be a complete substitute for certain of the ancillary services outlined above, nor be in the right location to mitigate local reliability issues. Moreover, PJM cannot mandate the expansion of DR and EE as these are market driven decisions. As a result, an effective compliance strategy requires the examination and integration of all of these resources, to the extent they are market driven, and adequate time to ensure their effective implementation of transmission solutions to local reliability problems in the event that new entry resources do not solve local reliability problems.

EPA Finding Para. M, Federal Register p. 25055:

"*Recent experience also shows that transmission upgrades to address reliability issues from plant closures can occur in less than 3 years.*"

PJM Comment:

The EPA does not cite any support for this sweeping conclusion. Just because transmission upgrades "can" occur in less than 3 years, does not mean that they will occur on such timetable in all circumstances. For instance, certain local reliability upgrades such as those that entail upgrades to existing substations can certainly occur in an expeditious manner. However, the kind of transmission upgrades that could be triggered by the retirement of Reliability Critical Units in congested portions of PJM would necessarily involve far more complex projects with extended delays due to the siting process.

For example, the Susquehanna-Roseland line is currently being held up by federal agency review. The need for this backbone transmission line was first identified by PJM and approved by the Board as part of 2007 RTEPP. At that time, the line was anticipated to be in service for 6/1/2012 to avoid identified reliability criteria violations. However, delays due to National Park Service review have delayed the in-service date of this line to 2015 at the earliest.[45] Similarly, the retirement by Exelon Generation of the Cromby Unit 2 and Eddystone Unit 2 requires 18 separate transmission system enhancements are required to address the identified thermal, voltage and short circuit violations. Thus, even though Cromby and Eddystone provided notice of deactivation in December, 2009, due to the need for such transmission enhancements the units are not going to actually shut down until May, 2012.In the interim, their operation is environmentally limited. [46]

Finally, the Benning Road and Buzzard Point generating units totaling 790 MW – located in the Potomac Edison Power Company's zone in Washington, D.C. – put it its deactivation request with PJM in February, 2007. Transmission reinforcements necessary to allow these generating units to retire, which include new circuits, upgrades

[45] http://pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx
[46] http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx

to existing circuits, new transformers, new capacitors and upgrades to existing terminal equipment, are not expected to be in service until more than five years after such notice in May, 2012.

EPA Finding Para. M, Federal Register p. 25056:

"Furthermore, if companies within an RTO/ISO wish to retire a unit, they must first notify the RTO/ISO in advance so that any reliability concerns can be addressed. The RTOs/ISOs have well established procedures to address such requirements."

PJM Comment:

As indicated above, the notification procedures are simply not adequate to meet the magnitude of changes and potential retirements that could result from implementation of the Proposed Rule. Although PJM is planning a filing at FERC to address certain reforms in its planning process which would ensure planning for "at risk" generation, even if PJM were successful in having those reforms approved by FERC, it would still require that the Final Rule be flexible enough to complement rather than work against those FERC-approved changes. PJM's proposed remedy outlined below will allow for this harmonization of the rule with changes in the planning process undertaken at PJM and the need to maintain system reliability during this important period.

EPA Finding Para. M, Federal Register p. 25056:

"The RTOs/ISOs also have a very important role to play and it appears that a number of them are already engaged in preparing for these rules. For instance, PJM Interconnection considered the impact of these anticipated rules at its January 14, 2011, Regional Planning Process Task Force Meeting, and Midwest Independent Transmission System Operator, Inc. (MISO) has also begun a planning process to consider the impact of EPA rules.

As discussed above, given the large reserve margins that exist, even after consideration of requirements of the proposed rule, EPA believes that any reliability issues are likely to be primarily local in nature and be due to the retirement of a unit in a load constrained area. As demonstrated by the work that PJM Interconnection and MISO are doing, RTOs/ISOs are required to do long range (at least 10 years) capacity planning that includes consideration of future requirements such as EPA regulations".

PJM Comment:

PJM appreciates the EPA's recognition of the important role of RTOs but believes that EPA has underestimate the local impacts of generation retirement on system security. In fact, it is PJM's important role concerning the reliability of the bulk power grid that necessitates PJM's Comments and Proposal contained herein.

Through the Regional Planning Process Task Force ("RPPTF"), PJM is engaged with its stakeholders in examining macro system-wide backbone transmission adequacy needs to serve load absent "at-risk" generation and meet NERC Loss-of-load-expectation standards. RTO/ISO long-range capacity planning ensures these standards are met. Moreover, PJM capacity planning does not entail the ability to compel the construction of NEW generating resources to replace resources which deactivate, let alone where, by when and how much; that is the province of market forces. RPPTF discussions do not address the specific reliability impacts of specific deactivated generation; PJM studies of "at-risk" generation are broadly conceived so as to avoid pre-determining or influencing a specific asset owners business decisions; thus to imply that PJM knows 10-years out which specific generators are going to retire is speculative and would put PJM in the position of endangering the competitive position of a specific owner's specific asset(s).

EPA Finding Para. M, Federal Register p. 25056:

"The RTOs/ISOs should consider the full range of options to provide any necessary replacement power including the development of both supply and demand side resources."

PJM Comment:

Here again, EPA's finding pre-supposes that the necessary transmission capability is in place to import this replacement power, which is in essence what the PJM's assessment of a deactivation request encompasses. Furthermore, as noted previously, PJM cannot compel the addition of generation or use of DR or EE.

EPA Finding Para. M, Federal Register p. 25055:

"EPA's assessment looked at the reserve margins in each of 32 subregions in the continental U.S. It shows that with the addition of very little new capacity, average reserve margins are significantly higher than required (NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25 percent). Although such an analysis does not address the potential for more localized transmission constraints, the number of retirements projected suggests that the magnitude of any local retirements should be manageable with existing tools and processes."

PJM Comment:

PJM agrees, the analysis does not address the potential for more localized transmission constraints as PJM explained more fully above. The fact that potential retirements have been understated, combined with the fact PJM could have as little as 90 days notice of retirement under its current FERC-approved rules, renders EPA's conclusion that adequate resources will exist incomplete and erroneous.

VI. PJM PROPOSED REMEDY TO SAFEGUARD RELIABILITY WHILE ENSURING TIMELY COMPLIANCE

PJM proposes the following Reliability Safeguard addition to the Proposed Rule to address, in a targeted unit-specific manner, the potential that a particular retirement or upgrade or set of retirements and upgrades triggers reliability issues that cannot be adequately addressed within the Proposed Rule's compliance timeframes. PJM's proposal addresses both use of the fourth year for additional time for compliance in such instances ***and*** the establishment of a mechanism to allow for additional time, on a targeted unit-specific basis, if as a result of unit upgrades or retirement, local reliability issues are triggered that cannot be addressed even within the four year timeframe set forth in the Proposed Rule.

A. Reliability Safeguard Running to January 1, 2016

PJM requests that EPA state either in the preamble to the Final Rule that the permitting authority should explicitly authorize or endorse the extensions to the three year compliance deadline for units which the RTO or relevant Reliability Coordinator[47] indicates are "Reliability Critical Units." Reliability Critical Units are those generating units, timely requesting deactivation (defined below) as a compliance response to the Proposed Rule, and subsequently identified by RTOs as units deemed critical to system reliability, including all of the ancillary services described herein. PJM believes Reliability Critical Units that have timely announced their deactivation should be eligible for a one year extension of the compliance obligation because deactivating a generating unit is simply another control option to comply with the Final Rule if the affected generating unit owner believes this is the least-cost compliance option, and is effectively no different from a generating unit choosing to install retrofits to meet the emissions rate standards that cannot get its retrofits in service by the January 1, 2015 compliance deadline. Units choosing deactivation as a compliance option would only be granted an exemption if under the RTO's independent analysis, they are deemed critical to system reliability and are required to stay in service for a defined period until transmission or replacement resource solutions could be placed into service.

B. Timely Notice of Retirement/Retrofit As a Condition Precedent to Availability of the Reliability Safeguard.

PJM is keenly aware that a one year extension request, if granted, may create incentives for generation owners faced with compliance decisions to wait as long as possible to submit their deactivation requests to PJM in the hope they can get their units extended beyond the January 1, 2015 compliance deadline if their units are deemed by

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[47] *See* n. 49, *infra*.

PJM in its subsequent deactivation study to be Reliability Critical Units. Under the current PJM Tariff generators are only required to provide 90 days notice of their intent to retire which means that generating units intending to deactivate to comply with the standards established in the Final Rule, could provide notice as late as September 30, 2014. With only 90 days, it is simply not possible that the required transmission or generation solutions identified by the RTO can be put in service by January 1, 2015. Given that at that point, a Reliability Must Run Agreement is potentially the only option available to PJM, generator owners can effectively attempt to extend the life of their units for an additional year or more with no intention of installing retrofits by simply delaying their deactivation request so they can effectively side-step compliance with the Final Rule through a potential mis-use of the extension process contemplated herein. From PJM's perspective, such an outcome does not serve reliability as such units are likely quite old and have poor availability as evidenced by high forced outage rates. Consequently, PJM requests the EPA provide guidance in the Final Rule that such an extension for deactivating units *only* be granted if the unit owners provide the RTO, with a copy to the EPA with notice of deactivation by the earlier of 12 months from the effective date of the Final Rule, or January 1, 2013, a full two years in advance of the January 1, 2015 compliance deadline.[48]

By January 1, 2013 PJM will have conducted it's 2015/2016 Base Residual Auction for Capacity Resources, and by that time generation owners will almost certainly have had to make their retrofit, repower, or retire decisions for compliance with the Final Rule based on whether or not the affected generating unit has cleared in the previous two auctions in which compliance costs could be reflected in their offers into the auction. For generating units that do not participate in RPM auctions and would otherwise be designated as capacity resources under the Fixed Resource Requirement this decision would have to be made at the same time as the 2015/2016 Base Residual Auction, and consequently those generation owners will have had to have made their compliance decision by January 1, 2013.

As a result, PJM believes that providing notice of deactivation at least 2 years prior to the compliance deadline combined with the proposed one year extension for Reliability Critical Units is prudent to allow for the development of transmission or generation solutions to identified local reliability problems on an individual generating unit basis.

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[48] Nothing in this proposal should be read as limiting the ability of units which are retrofitting but cannot complete such work by the compliance deadline from also being eligible for a compliance extension. The proposed "safety valve" is intended to provide a safe harbor for those retiring generators who meet the eligibility criteria – including providing the advanced notice of retirement – as outlined above. Nothing in this proposal eliminates a generating owner from petitioning the Secretary of Energy to excise its authority under Section 202(c) of the Federal Power Act and Section 301(b) of the Department of Energy Organization Act to order the unit remain operational. Nor would this preclude a generator from working with EPA to establish a compliance schedule.

C. Availability of Additional Extensions Beyond the Four Year Period Upon Certification by the RTO of Reliability Problems Resulting from Unit Retirement or Delays in Completing Upgrades

As explained above, the scale of potential generating unit deactivations as a result of the Final Rule may create a volume of transmission reinforcements that may force some needed transmission solutions beyond the four year window set forth in the Proposed Rule. PJM has already seen 7,350 MW of installed coal capacity not clear in the 2014/2015 Base Residual Auction, and an additional 7,000 MW of coal capacity retirements have been announced by FRR entities in PJM. Moreover, a recent PJM analysis of units at risk has independently identified approximately 11,000 MW of coal capacity that requires additional revenues to cover the cost of retrofits in excess of the Net Cost of New Entry for a natural gas combustion turbine.

Consequently, there may be instances in which solutions to reliability problems identified in a unit deactivation process could require extensions for more than one additional year and go beyond the initial four years. For Reliability Critical Units that have provided their RTO notice by the earlier of within 12 months of the date of the effective date of the Final Rule or January 1, 2013 that that they intend to deactivate, but the unit owner does *not* intend to construct on-site replacement power, EPA should allow unit owners to avoid non-compliance penalties through a schedule of compliance for the period necessary for the RTO to ensure the availability of sufficient replacement resources or transmission solutions. The RTO would review these limited situations with its stakeholders through its public planning process and, through that public process, would be in a position to indicate to EPA the timeframe that is necessary to do so. PJM recognizes that ordinarily states issue Title V permits and that a schedule of compliance could be included there or, alternatively, in a consent decree. The situation would not be allowed to continue open-ended. Rather, the schedule of remedial measures proposed by the asset owner would include a mandatory shutdown on a date certain based on the public information available from the RTO. 40 C.F.R. § 70.5(c)(8)(iii), *Sierra Club v. Johnson*, 541 F.3d 1257, 1260-61 (11th Cir 2008). PJM seeks acknowledgement and recognition by EPA that the RTO's indication that a unit , which has provided timely notice to the RTO, is a Reliability Critical Unit would be an appropriate exercise of EPA's discretion with respect to the timing of an existing generating unit's compliance with the Final Rule. PJM urges that the Final Rule allow for this contingency and establish a clear up-front process, such as described herein, so that all affected entities are: 1) aware of the importance of timely notice to the RTO and EPA and 2) are clear on how they may utilize this limited "safe harbor" option.

In a nutshell, timely notice of deactivation to the RTO and an identification that unit in question is a Reliability Critical Unit which cannot be replaced with alternative resources or transmission reinforcements in the four year time allotted would be allowed a limited "safe harbor" from penalties until the RTO indicates that adequate resources have been put in place to address the reliability concern. The RTO's findings would be developed in open stakeholder processes and made available for the EPA's (or state air permitting authority's) ultimate determination as to whether to grant such an extension.[49] The specifics as to how often the unit can operate within this time period, at what levels and during what periods are best addressed on a unit-specific case by case basis. PJM pledges to work with EPA on such individual cases so that EPA has the benefit of PJM"s independent reliability analysis and knowledge of grid operations.

VII. CONCLUSION

PJM believes an upfront, well-defined process to handle these extensions beyond one year given the two year deactivation notice requirement should be extremely rare, and hopefully never used. However, acknowledging such a possibility exists, and putting a process in place in the Final Rule, is essential to provide certainty to the wholesale power market that reliability will always be maintained. Additionally, such a process enshrined in the Final Rule provides certainty to generators that may request deactivation that if they are asked to remain in service to maintain reliability, they will not face the possible liability of being deemed non-compliant with the Final Rule while providing critical reliability needs to the entire system. Such a process may entail the EPA authorizing or endorsing a schedule of compliance in the affected generating unit's Title V permit through the implementing State Authority, in coordination with the RTO; and/or a Consent Decree between EPA, the State Authority and the Generation Owner developed and signed prior to the end of the compliance period, or a formal extension through a streamlined process including EPA, and the implementing state authority working with the asset owner and the RTO to grant extensions beyond January 1, 2016.

As the preceding discussion demonstrates, the analysis supporting the Proposed Rule has underestimated the risks to reliability of electric supply in light of the hard deadlines imposed pursuant to Clean Air Act § 112. Moreover, as EPA indicated, unit owners must only give 90 day notice prior to shutdown in the PJM region, 76 FR 25056. The requirement to be in compliance three years following publication in the federal register, 40 CFR §63.9984, may result in the shutdown of certain units that are critical to the reliability of electric supply on a timeline that is faster than the time necessary to replace the power or upgrade transmission.

Thus, it is not so much the technology requirements imposed under the Proposed Rule, but rather the very tight timeframe imposed by § 112 of the CAA that is incorporated into the Proposed Rule. PJM recognizes that there are limitations on EPA's ability to depart from this timeline. This was much less of an issue when EPA proposed in the Clean Air Mercury Rule to control mercury emissions under § 111 of the

[49] Such a process could be made available to Reliability Coordinators in non-RTO regions although in such regions the Reliability Coordinator and the unit owner could both be under a single corporate parent. As a result, more care would be needed to ensure adequate functional separation. Such issues do not arise in the RTO context since, as noted previously, the RTO is wholly independent of all market participants including unit owners.

Clean Air Act, because the approach was cap and trade compliance, which allowed cleaner units to offset higher emitting units.[50] Under the NESHAP proposal, in contrast, each existing unit must come into compliance, *i.e.* there is limited opportunity to combine units for compliance purposes or develop an overall compliance plan. As a result, PJM anticipates that there will be units where retrofitting is not cost-effective that will be shut down. Shutdown of reliability critical units before a replacement resource or a transmission solution can be accomplished could, in targeted situations, risk reliability of the delivery of electric power. These Reliability Critical Units would not have been shown in EPA's modeling because of the modeling methodology.

PJM reiterates that it is not itself requesting a blanket delay of the implementation of the Final Rule, nor is PJM requesting blanket extensions for all units requesting deactivation.[51] PJM is requesting EPA provide a clear process in its Final Rule is to allow for one year extensions for deactivating units if they provide a deactivation notice by the earlier of 12 months from the effective date of the Final Rule or January 1, 2013 and are deemed to be Critical Reliability Units.PJM is also requesting that this process account for the possibility that extension of more than one year beyond January 1, 2016 will be necessary for some units requesting deactivation to comply with the Final Rule due to the large potential volume of deactivation requests and the possible volume of solutions that must be put into service such they cannot all be completed by January 1, 2016.

PJM stands ready to work with EPA on this important issue and appreciates this opportunity to provide comment.

/s/ Craig Glazer
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[50] PJM recognizes that the Clean Air Mercury Rule was vacated by the U.S. Court of Appeals for the DC Circuit in *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

[51] PJM takes not position on any requests of others for a blanket extension of compliance with the Final Rule.

Mr. WHITFIELD. I want to thank the witnesses. Thank you for your patience. We appreciate your taking time to give us your thoughtful comments, and we look forward to working with you as we move forward to help solve these issues. Thank you.

And the record will stay open for a minimum of 10 days for any additional comments or documents to be presented.

With that, the hearing is adjourned.

[Whereupon, at 12:52 p.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

Mr. Chairman –

Thank you.

This hearing is about the potential cumulative impacts of new and proposed EPA regulations on the power sector and how they might effect reliability. I can tell you that my home state of Nebraska is very concerned.

Yesterday in the mark-up of legislation dealing with 2 of the regulations coming out of EPA, I mentioned that poverty is at an all time high since 1993. We have been focusing on job lost associated with these rules. Well, now we learn that not only will people be out of work, but potentially could be left in the dark as well.

I have 3 documents I would like to enter into the record.

The first is a letter from our governor to Administrator Jackson expressing his concerns with the number and substance of the regulations.

The second is an article from The Grand Island Independent.

The last is an article from Lincoln Journal Star that ran just yesterday.

The independent article reported on a meeting held by our State Attorney General Jon Bruning. On September 6, he hosted what was called an "EPA Summit." The 3 concerns addressed were

- possible power plant closings,
- employee layoffs
- increases in power rates

General Bruning is planning to work with other state attorneys generals to have the new regulations delayed or revised.

According to the Grand Island utility manager, just the Cross-State Air Pollution Rule will require an investment of 35 to 40 million dollars in equipment to comply.

The city of Freemont may have to spend as much as $35 million over the next 5 years.

Omaha Public Power district estimates a possible 4 percent cost increase as well.

These are just a few of the concerns of the folks back home. I look forward to hearing our witnesses and asking if they have creative solutions to these concerns.

I yield back.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

October 20, 2011

The Honorable Ed Whitfield, Chairman
Subcommittee on Energy and Power
U.S. House of Representatives
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515-6115

Dear Chairman Whitfield:

Thank you for your October 4, 2011 letter which contained additional questions for the hearing record on "The American Energy Initiative." Please find enclosed my responses to your questions.

Please do not hesitate to contact me if you have any further questions or would like to discuss these responses.

Sincerely,

Jon Wellinghoff
Chairman

Enclosure

cc: The Honorable Bobby Rush, Ranking Member
Subcommittee on Energy and Power

The Honorable Ed Whitfield

1. **FERC staff completed and presented to EPA a PowerPoint presentation entitled "Potential Retirement of Coal Fired Generation and its Effect on System Reliability (Preliminary Results)" (see attached). Slide 29 of this presentation is entitled "Next Steps" and details several FERC staff recommendations, including directing industry to "openly assess the reliability and adequacy impacts of retirement of at risk units." FERC staff then identified a list of factors that any such assessments should consider, including frequency response, voltage profile and bulk power system loadings, stability, loss of load probability calculations, and deliverability of resources through planning studies. The slide also provides that FERC staff will continue to "improve screening methodology with industry cooperation" and "conduct reliability studies."**

    a. Please describe whether any of the identified "Next Steps" of Slide 29 have been completed by FERC staff or are in the process of being completed. Please provide any related documentation or materials.
    Answer: See answer "b." below.

    b. If no "Next Steps" have been completed, please detail the decision-making process resulting in the conclusion that the recommendations of FERC staff should not be followed.
    Answer: Intervening regulatory actions have superseded pursuing these specific next steps.

2. **In response to a hearing question regarding whether FERC has directed planning authorities to undertake the studies and actions set forth in Slide 29 of the FERC PowerPoint presentation (see attached), you testified:**

    "Yes. In fact, in Order 1000, we very specifically say that they [the planning authorities] must consider both federal and State public policies which would include the EPA [power sector] rules. So yes, we absolutely have done that in Order 1000."

    However, Order No. 1000 expressly explains that: "Some commenters request that we specify EPA regulations ... as Public Policy Requirements driving potential transmission needs relevant for consideration in the transmission planning process .... [] [W]e decline to mandate the consideration of transmission needs driven by any particular Public Policy Requirement .... "(emphasis in original). Consequently, Order No. 1000 does not mandate that EPA's power sector rules be considered by regional planning entities. Moreover, Order No. 1000 compliance filings are not due for another 12 to 18 months. Meanwhile, many of EPA's regulations will become final well before Order No. 1000 compliance plans are ever approved by FERC.

a. Please explain how Order No. 1000 requires planning authorities to complete the studies and actions set forth in Slide 29 of the FERC PowerPoint presentation.
Answer: See answer "2.b." below.

b. Please explain how Order No. 1000 will mitigate short-term reliability concerns resulting from EPA's power sector rules given that: (1) consideration of the EPA rules by regional planning entities is not mandatory; and (2) FERC consideration of Order No. 1000 compliance filings will not begin until well after EPA's power sector rules will have become final.
Answer: An Order 1000 compliance filing may be considered by FERC upon its filing by a planning authority. To the extent the planning authority determines it necessary to make that filing prior to due date for filing it may do so. In addition every planning authority has a responsibility under FERC approved reliability regulations and under Order 1000's predecessor, Order 890, to conduct planning for reliability.

3. **Twice this year FERC has joined with NERC to study and issue detailed reports assessing various reliability matters. Last month FERC and NERC produced a joint 3 SO-page report on "Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011." Similarly, FERC recently announced that FERC and NERC will complete a joint reliability inquiry into the recent outages in Arizona and Southern California.**

a. Does FERC intend to coordinate with NERC to complete a comprehensive analysis of the impacts of EPA's power sector rules on reliability?
Answer: FERC will coordinate with NERC and the planning authorities to help ensure that reliability of the bulk power system is maintained.

b. If FERC does not intend to complete a joint report with NERC, please detail the decision-making process resulting in the conclusion that a joint analysis with NERC is not justified in this assistance.
Answer: See answer "a." above.

4. **Section 215(g) of the Federal Power Act provides that the Electric Reliability Organization - NERC in this case - "shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America." NERC completed a study last October on the impact of EPA's rules on reliability.**

a. Did NERC present the results of its October 2010 study to FERC? If so, please provide details regarding when the meeting occurred, who attended, what was discussed, and whether the meeting resulted in plans for NERC or FERC (jointly or individually) to undertake future actions or next steps as a result of the NERC results, including updated or additional studies. Please

describe any such follow-up activities or meetings between FERC and NERC as related to the NERC study.
Answer: No, not formally or in person. Results were sent electronically.

b. Has FERC directed NERC to complete an updated study based on new information? If not, why not?
Answer: No. It is our understanding that NERC is in the process of doing an update that will be released in mid November.

5. **During the September 14th hearing, Commissioners Moeller and Spitzer both emphasized the need for the Commission to be more proactively involved in determining the cumulative impacts of EPA's regulations on the electric grid. They suggested, at a minimum, that FERC needs to convene an open and transparent process to assess the cumulative impacts of EPA's power sector rules. The Commissioners suggested that such a process should occur before the EPA rules are finalized.**

a. Does FERC intend to undertake - prior to the EPA power sector rules becoming final- a Commission-led process to formally and thoroughly evaluate the impact of EPA's rules on reliability, including but not limited to the hosting of a public workshop or technical conference or the completion and publication of a formal cumulative assessment? If so, please provide the following details:

i. the scope of the process;
ii. the timeline for carrying out the process;
iii. the participation of other agencies, entities, and officials *(e.g.,* federal agencies, NERC, RTOs, state public utility commissions, industry); and
iv. plans for updated or new reliability studies or assessments, including joint studies with NERC or regional and sub-regional studies overseen by FERC.

Answer: FERC intends to conduct our 3rd reliability summit at the end of November where one of the potential topics of discussion will be emerging issues, including processes used by planning authorities and other entities to identify reliability concerns that may arise in the course of compliance with Environmental Protection Agency regulations, and the tools and processes (including tariffs and market rules) available to address any identified reliability concerns.
i.-iv. The details of the summit are currently under development.

b. If FERC does not intend to undertake a formal and transparent process to evaluate potential reliability implications, please detail the decision-making process resulting in the conclusion to forego such a process, including consideration of the positions of Commissioners Moeller and Spitzer.
Answer: See answer "5.a." above.

6. **You have emphasized the importance of regional and local planning entities, including state public utility commissions, to ensuring reliability, particularly at the local level. The State of South Carolina recently petitioned FERC requesting the Commission to convene a joint board with state regulators to study the potential impacts of EP A's power sector rules on reliability.**

a. Do you believe this would be a worthwhile federal-state partnership that could help identify and mitigate potential reliability problems? If not, why not? If you agree such a partnership is worthwhile, do you plan to establish a joint board with South Carolina state regulators? With other states?

b. When do you plan to respond to South Carolina?
Answer: The South Carolina petition is currently pending before the Commission and any discussion of it would be inappropriate at this time.

7. **EPA's proposed Utility MACT Rule was published in the *Federal Register* on May 3, 2011. The preamble of the proposed rule expressly provides that:**

"Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained"

This statement clearly contemplates that reliability issues should be identified and addressed simultaneously with the rulemaking process to ensure these issues are resolved to the extent practicable prior to finalization of the rules. Yet, according to the information and answers you provided to the Committee, communications between FERC staff and EPA regarding the potential impacts of EPA rules on electric reliability ceased after May 3, 2011 and "have not been ongoing."

a. Were you aware that EPA's proposed Utility MACT Rule expressly calls upon FERC and DOE to cooperate in assuring that reliability is maintained and that this coordination is to occur before the rule becomes final?
Answer: The quoted passage of the *Federal Register* notice cited refers to FERC identifying *"authorities and policy tools"* regarding electric reliability. FERC has done that for EPA in a series of meetings that have been previously described to the Subcommittee.

b. If so, how do you reconcile the fact that communications between FERC and EPA apparently ended on May 3, 2011, the same day as EPA's proposed rule was published but well before the rule will become final?
Answer: See answer to "7.a." above.

c. If EPA and FERC are continuing to coordinate, please outline the process by which the Commission and EPA are doing so to further evaluate the reliability impacts of EPA's power sector rules. Please specify the type of coordination *(e.g.,* staff level meetings, information sharing, etc.) and identify the specific reliability topics to be evaluated as part of your ongoing coordination.
Answer: See answer to "7.a." above.

d. In the absence of any additional coordination with EPA, please describe the process the Commission intends to undertake to evaluate the cumulative impacts of EPA's power sector regulations on the reliability of the electric grid. Please include the following information:

i. the scope of the process;
ii. the timeline for carrying out the process;
iii. the participation of other agencies, entities, and officials *(e.g.,* federal agencies, NERC, RTOs, state public utility commissions, industry); and
iv. plans for updated or new reliability studies or assessments, including joint studies with NERC or regional and sub-regional studies overseen by FERC.

Answer: See pre-filed testimony of Chairman Jon Wellinghoff submitted to the Subcommittee for the September 14' 2011 hearing entitled "The American Energy Initiative".

8. **You have indicated in written and oral testimony that EPA's power sector rules will have regional and local reliability impacts. Likewise, Commissioner Moeller testified that EPA's proposed rules will impact different regions in different ways, and therefore "analyzing the impact must be done on a granular level down to the specific load pockets that are affected."**

a. Please identify any region, sub-region, electric control areas, or "specific load pockets" in the United States that may experience degraded reliability caused by EPA's power sector rules. Please detail the basis for any identified area.
Answer: Such areas may be identified by the planning authorities. See answer to "7.d." above.

b. If FERC has not identified any such region, sub-region, electric control areas, or "specific load pockets," please describe the Commission's plans to evaluate the "granular" reliability impacts of EPA's power sector regulations.
Answer: See answer to "8.a." above.

c. If FERC lacks the tools or information to be able to identify any region, sub-region, electric control area, or "specific load pocket" in the United States that may experience degraded reliability caused by EPA's power sector rules, please describe how FERC is coordinating with, or directing, EPA, NERC, and regional and local planning authorities to identify such areas and assess potential reliability impacts and develop any related mitigation plans.
Answer: See answer to "8.a." above.

9. **In your testimony, you refer to a reliability "safety valve" as a way to mitigate reliability concerns by permitting a waiver or case-specific extension to avoid reliability threats and potential emergencies.**

a. Please document all discussions FERC has had regarding such a "safety valve" approach with representatives of EPA, any RTO or ISO, or state public service commissions.
Answer: I spoke with Lisa Jackson, Administrator and Gina McCarthy, Assistant Administrator for the Office of Air and Radiation about the safety valve on Friday, October 14. On August 10, 2011, PJM held a briefing for FERC Staff on PJM's Comments and Joint Comments on EPA's Hazardous Air Pollutants Rule.

b. Please describe any "safety valve" proposals considered or under consideration by FERC or any other federal agency that would allow utilities to operate under the EPA power sector regulations until reliability concerns have been mitigated.
Answer: The proposal as it is understood is to EPA and not FERC but, depending on EPA's response, could involve a role for FERC in reviewing certain claims of future violations of reliability standards.

c. Please cite any provision of any of EPA's proposed power sector regulations upon which a utility could rely in knowing an extension of the regulatory or statutory compliance period is available as a "safety valve" in order to ensure reliability.
Answer: Contents of EPA regulations are under the control and within the knowledge of EPA and not FERC.

d. Wouldn't it be more prudent to extend the compliance deadlines of the EPA power sector rules before an emergency occurs, rather than hoping that emergency waiver authority can stave off a reliability crisis after the fact?
Answer: Any decision in this regard is within the authority of EPA and not FERC.

10. **You testified that "we [FERC] are directing EPA to in fact interface directly with the planning authorities like PJM, like ERCOT and others, and to provide them all the data that EPA has to help those planning authorities have an adequate handle on what they need to do to do their job to ensure reliability in this country." Yet in a written response to a pre-hearing**

Committee question regarding whether EPA followed FERC's recommendation to coordinate with regional planning authorities, you stated that "I do not know what actions EPA has undertaken to our earlier conversations."

a. Has FERC - as you suggest - "directed" EPA to interface with regional planning authorities? If so, please describe the details of FERC's directive and what actions EPA has taken to comply with FERC's request?
Answer: We have not "directed" EPA in any legal sense as FERC has no statutory authority to do so. FERC "directed" EPA in the sense that we informed them of the role of the planning authorities and made them aware of their functions and identities. We "directed" EPA to the planning authorities as the proper place to interface on the potential impacts of EPA emissions regulations on reliability.

b. If FERC has not directed EPA to take such action, do you believe FERC has the authority to "direct" EPA to interface with regional planning authorities? Please explain why or why not. If you believe FERC has such authority, do you plan to direct EPA to consult with regional and local planning authorities?
Answer: See answer "10.a." above.

c. If you do not believe FERC has such authority, please describe what actions the Commission intends to take to ensure that EPA follows the recommendations of FERC to coordinate with regional and local planning authorities. Please include specific plans to coordinate and meet with EPA, regional and local planning entities, and other interested stakeholders.
Answer: See answer to "10.a." above.

11. **You testified that you have had discussions with David Owens, Executive Vice President of Business Operations at the Edison Electric Institute, regarding the need for a "workshop" that would bring together affected stakeholders to discuss reliability concerns resulting from the EPA power sector rules. You suggested that Mr. Owens opined that such a workshop was not something that would be necessary from an industry perspective.**

a. Please provide the date(s) on which this conversation or meeting occurred.
Answer: I talked to Mr. Owens on September 13, 2011.

b. Please describe the scope and purpose of the meeting and provide a summary of what was discussed, including Mr. Owen's reasons for why investor-owned utilities do not feel a public workshop on reliability matters related to EPA's rules is necessary.
Answer: No meeting took place. The discussion was in the course of a telephone call. Mr. Owens never mentioned a meeting.

12. **During your testimony you began to describe a meeting you had with a representative or representatives from PJM shortly before the September 14th hearing. Your statement appears to have been in regard to the fact that regional planning entities are already in the process of evaluating the regional and local reliability impacts of EPA's power sector rules.**

a. Please provide additional details of this meeting, including the following:

i. identify the PJM representatives with whom you met;
Answer: Craig Glaser, Andy Ott, Stu Bresler.

ii. the date(s) on which the meeting occurred;
Answer: September 6, 2011.

iii. a description of the scope and purpose of the meeting; and
Answer: Price Responsive Demand Filing and to discuss Brattle's Analysis of PJM Capacity Market Design and Results Report.

iv. a summary of what was discussed during this meeting, including details provided by PJM representatives with respect to the actions PJM has taken to address reliability matters resulting from the EPA power sector rules.
Answer: See answer "12.a.iii." above. The meeting was not to specifically discuss reliability but there was mention in the discussion of the capacity market design of the responsiveness of the capacity markets to the pending proposed EPA emissions regulations and the positive impact of that response on reliability.

b. Please provide the details of any similar meetings you or FERC staff has had with PJM or other RTOs and ISOs regarding the actions such entities have taken to address reliability matters resulting from the EPA power sector rules.
Answer: There have been no similar meetings.

13. **What procedures do you use to ensure that your fellow Commissioners are informed about the activity of FERC staff related to how EPA's power sector rules may impact reliability and prices? If a Commissioner has questions for FERC staff, how does he or she obtain an answer?**
Answer: Regular periodic one-on-one meetings with each Commissioner and individual staff meetings with each Commissioner. Commissioners are free to meet with and ask staff any questions that they may have on any Commission subject.

14. **Please provide the date of when you first received a copy of the Commission's "informal" study analyzing the reliability impacts of EPA's power sector rules.**
Answer: Sometime during the 4th quarter 2010 or the 1st quarter 2011.

15. **Do you believe the study completed by FERC staff was either "informal" or "irrelevant?" If so, please provide the reasons why you consider FERC's study to have been "informal" and/or "irrelevant."**
Answer: Please see "Caveats" to study on slide "1" of the study. In addition, please see the transcript of the hearing at P. 24-25, 82, and 108.

16. **Do you believe the Commission should "formalize" its "informal" assessment of how EPA's power sector rules might impact reliability and prices?**
Answer: No.

17. **Have you requested FERC staff to cease work on evaluating how EPA's power sector rules might impact reliability and cost/price issues? If not, what work by each FERC division is continuing or ongoing?**
Answer: It has been indicated to the FERC staff that detailed study and analysis of potential reliability impacts of the proposed EPA emission requirements should be conducted by the appropriate planning authorities.

18. **Please provide any documents from the following FERC offices that discuss, involve, or consider EPA regulations related to prices or reliability regarding electricity, or to prices or reliability regarding natural gas: Office of Enforcement; Office of Energy Policy and Innovation; Office of Energy Projects; Office of Electric Reliability; Office of Energy Market Regulation; Office of External Affairs; Office of General Counsel; Office of the Executive Director; and Office of the Secretary.**
Answer: All documents have been previously provided.

19. **If the type of work that FERC staff completed is "irrelevant," as has been suggested, then would it not be true that the same type of work being completed by NERC also is irrelevant?**
Answer: As stated previously, the NERC study examined scenarios that have changed since it was issued. Thus, I cannot comment on the usefulness of NERC's report. The question should be directed to NERC as to the use of their study.

20. **Please compare the analytical work done in the FERC "informal" study to the analytical work completed by EPA in its reliability modeling.**

a. For each component of the work done by EPA in its reliability modeling, where is that component reflected in the work done by FERC? And vice versa?
Answer: Such a comparison has not been performed.

b. Does this demonstrate that EPA reviewed fewer issues than FERC? If so, then isn't the analytical work done by EPA even less formal than the

allegedly "informal" work completed by FERC staff? If not, please provide each and every reason why the EPA study is superior to the FERC assessment.
Answer: See answer to "20.a." above.

21. **Please describe the Commission's efforts on the following reliability issues: (1) cybersecurity; (2) standards; (3) event analysis; (4) investigations; and (5) penalties. Please contrast these efforts with the Commission's efforts on how EPA's power sector rules might impact reliability.**
Answer: The Commission has specific statutory authority to enact reliability standards and to enforce those standards as to retrospective violations through investigations and the imposition of penalties. Such standards may encompass cyber security. The Commission oversees event analyses that are conducted by NERC for specific reliability events. Such events may also prompt FERC reliability investigations. EPA's power sector rules have potential prospective impacts that are best addressed in the reliability planning activities of the planning authorities that are required and informed by FERC's reliability rules and Orders 890 and 1000.

22. **Does your Office of Enforcement, Division of Market Oversight, monitor issues that have an impact on natural gas and electricity prices? If so, why not monitor impacts that EPA's regulations might have on the cost of natural gas and electricity?**
Answer: The Division of Energy Market Oversight (DEMO) does market oversight in an effort to detect fraud and market manipulation and to examine market conditions in the wholesale natural gas and electric power markets, as well as related energy and financial markets. DEMO assesses factors that relate to the competitiveness, fairness, and efficiency of wholesale energy markets; its analysis is anchored in actual events and trends. DEMO does not perform price modeling, nor does it attempt to predict future prices.

23. **What analyses did FERC perform to make sure that wholesale energy markets following implementation of the Demand Response Compensation Rule will produce results consistent with making investments to comply with the EPA power sector rules? Did FERC ask EPA to analyze the air emission impacts of shifting power generation from power plants required to meet Clean Air Act standards to those off the grid (so-called "behind the meter" generation) that is not subject to the same emissions standards?**
Answer: No analysis was conducted relative to the Demand Response Compensation Rule and the EPA power sector rules. It is our understanding, however, that behind the meter generation is subject to certain EPA emissions regulations. And as such, those facilities are usually subject to more stringent environmental regulations than remotely sited central station power plant facilities due to being primarily located in urban non-attainment areas.

24. **What analyses did FERC conduct, and what specific safeguards exist in the Commission's final Demand Response Compensation Rule, to assure Congress that paying businesses and manufacturers <u>not</u> to use electricity to produce goods and services will not have negative economic consequences?**

<u>Answer</u>: The Demand Response Compensation Rule is intended to provide businesses and manufacturers with a market mechanism to compensate them for changing usage patterns in ways that is both compatible with their business needs but also beneficial to the grid by lowering prices for all consumers. Thus there are primarily positive economic consequences from the implementation of the rule by both providing compensation to businesses that choose to participate in the wholesale demand response markets and lower prices for all consumers on the grid.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

Office of Commissioner Philip D. Moeller

October 17, 2011

The Honorable Ed Whitfield
Chairman
Subcommittee on Energy and Power
United States House of Representatives
Washington, DC 20515

Dear Chairman Whitfield:

Thank you for your continuing interest in our work at the Federal Energy Regulatory Commission (FERC), and for providing me with an opportunity to express my views on the subject of how actions by the Environmental Protection Agency (EPA) could impact the reliability of our nation's electric system.

Enclosed is my response to your questions. As always, I am available to meet with you to discuss this or any other matter concerning the work of the Commission.

Sincerely,

Philip D. Moeller

**Answers of Commissioner Philip Moeller to the Questions
Asked by the Honorable Ed Whitfield**

Question 1. What procedures do you use to ensure that your fellow Commissioners are informed about the activity of FERC staff related to how EPA's power sector rules may impact reliability and prices? If a Commissioner has questions for FERC staff, how does he or she obtain an answer?

Answer: Prior to July 27, 2011, my personal staff was able to ask detailed questions to FERC staff about their ongoing activity with respect to EPA issues. After that date, the Chief of Staff asked that any further requests of my office on this topic should go through him.

Question 2. Please provide the date of when you first received a copy of the Commission's "informal" study analyzing the reliability impacts of EPA's power sector rules.

Answer: On about May 27, 2011, when I received a computer disk of information that was to be sent in response to the letters from Senator Murkowski and Representative Upton.

Question 3. Do you believe the study completed by FERC staff was either "informal" or "irrelevant?" If so, please provide the reasons why you consider FERC's study to have been "informal" and/or "irrelevant."

Answer: No, the study is not "informal", nor is it "back-of-the-envelope" or "irrelevant". As stated by the Chairman in the August 1, 2011 letter to Senator Murkowski:

> *In performing the informal assessment, Commission staff chose certain factors to consider, such as S02 controls, age of the plant, and whether the plant owner had already announced plans to retire the plant. Commission staff then decided to weight each factor. As these inputs to the informal assessment have changed, projected outcomes would necessarily change. Therefore, this informal assessment offered only a preliminary look at how coal-fired generating units could be impacted by EPA rules, and is inadequate to use as a basis for decision-making, given that it used information and assumptions that have changed.*

Based on this description, and my continuing experience with the first-rate quality of our staff, I believe that this work can be used as a basis for decision making by the EPA as it considers its proposed rules. While the Chairman contends that the study is "inadequate to use as a basis for decision-making, given that it used information and assumptions that have changed," that problem can be fixed if the staff is directed to update the study to include the most recent data.

Question 4. Do you believe the Commission should "formalize" its "informal" assessment of how EPA's power sector rules might impact reliability and prices?

Answer: Yes.

Question 5. Have you requested FERC staff to cease work on evaluating how EPA's power sector rules might impact reliability and cost/price issues? If not, what work by each FERC division is continuing or ongoing?

Answer: No, I have not made that request. I do not know what work by each FERC division is continuing or ongoing, but as a Commissioner of FERC, I would like to know the answer to that question.

Question 6. Please provide any documents from the following FERC offices that discuss, involve, or consider EPA regulations related to prices or reliability regarding electricity, or to prices or reliability regarding natural gas: Office of Enforcement; Office of Energy Policy and Innovation; Office of Energy Projects; Office of Electric Reliability; Office of Energy Market Regulation; Office of External Affairs; Office of General Counsel; Office of the Executive Director; and Office of the Secretary.

Answer: Over the past few months, I have been sent various documents regarding EPA that were generated by the above-listed Offices at FERC.

For example, my office has e-mail messages from the Office of Electric Reliability and other FERC Offices in response to my inquiries about three EPA documents. The documents of concern were a 41-page document identified as EPA-HQ-OAR-2009-0234-3003.2, a "Response to 03/04/11 Interagency Comments" and a 7-page document identified as EPA-HQ-OAR-2009-0234-3025.1, "Response to 03/09/11 Interagency Comments" and a 15-page document that described EPA's model for reliability that was developed by ICF Consulting. Among other statements in those documents, I was interested in the background behind this statement that was apparently made by EPA:

> *EPA could remove this from the justification for the rejecting the beyond-the-floor analysis if FERC believes there is sufficient gas for all coal- and oil-fired electric generation to be replaced by natural gas without the use of hydraulic fracturing.*

And I was similarly interested in the background behind this statement, also apparently made by EPA:

> *We presented the discussion in addition to our concerns with the costs of fuel switching and about the available supply of natural gas (which FERC contests).*

My office also has e-mail messages from the Office of Energy Policy and Innovation to the Commissioner's Advisors, and their attachments, which include an e-mail message from staff in the Office of the Executive Director to staff in the Office of Management and Budget at the White House. I also have documents from the Office of Enforcement, Division of Energy Market Oversight.

Given the small size of my staff and my ongoing work in preparation for the Commission's monthly meeting next Thursday, I do not have the documents ready for delivery at this time. In particular, I will need to have my staff consult with FERC staff to determine if the documents have already been provided to you by the Chairman.

Question 7. If the type of work that FERC staff completed is "irrelevant," as has been suggested, then would it not be true that the same type of work being completed by NERC also is irrelevant?

Answer: As stated above, I do not believe that the work of our staff is "irrelevant". Thus, I believe that the work that is ongoing at NERC may also be useful in considering the reliability impacts of proposed EPA rules.

Question 8. Please compare the analytical work done in the FERC "informal" study to the analytical work completed by EPA in its reliability modeling.

a. For each component of the work done by EPA in its reliability modeling, where is that component reflected in the work done by FERC? And vice versa?

Answer: According to an e-mail message dated May 10, 2011 that my personal staff received from the Office of Electric Reliability:

> *EPA's reliability analysis has been limited to generation adequacy assessments for 2015. The analysis only includes the expected retirement caused by two of its rulings (does not include coal residuals, green house or clean water). FERC Staff has pointed out to EPA that a reliability analysis should explore transmission flows on the grid, reactive power deficiencies related to closures, loss of frequency response, black start capability, local area constraints, and transmission deliverability. In addition, we have indicated to EPA the regional transmission planners would be best suited to run these studies. We have suggested that EPA interact with the ongoing initiatives at PJM and MISO which are assessing the effect of projected retirements on their grids.*

While I do not believe that this response comprehensively answers this question, this is all the information that I have at this time.

b. Does this demonstrate that EPA reviewed fewer issues than FERC? If so, then isn't the analytical work done by EPA even less formal than the allegedly "informal" work completed by FERC staff? If not, please provide each and every reason why the EPA study is superior to the FERC assessment.
Answer: Yes, and in that sense, under an assumption that FERC's work is "informal", then the work conducted by EPA would be equally "informal".

Question 9. Please describe the Commission's efforts on the following reliability issues: (1) cybersecurity; (2) standards; (3) event analysis; (4) investigations; and (5) penalties. Please contrast these efforts with the Commission's efforts on how EPA's power sector rules might impact reliability.

Answer: The Commission allocates significant resources to all five of these topics, and all of them are critical to the reliability of the power grid. In contrast, despite the potential impact of EPA rules on the reliability of the power grid, I do not know if the agency will allocate more resources to that issue.

Question 10. Does your Office of Enforcement, Division of Market Oversight, monitor issues that have an impact on natural gas and electricity prices? If so, why not monitor impacts that EPA's regulations might have on the cost of natural gas and electricity?

Answer: Yes, and I believe that as part of its efforts to monitor market issues, our Division of Market Oversight should monitor the impacts of EPA regulations on prices for natural gas and electricity.

Question 11. During the hearing, there were several references to a reliability "safety valve" as a way to mitigate reliability concerns by permitting a waiver or case-specific extension to avoid reliability threats and potential emergencies.

Please document all discussions FERC has had regarding such a "safety valve" approach with representatives of EPA, any RTO or ISO, or state public service commissions.
Answer: On or about August 10, 2011, staff at PJM met with my personal staff on PJM's Comments and Joint Comments on EPA's Hazardous Air Pollutants Rule. On August 29, 2011, I met with representatives of the Midwest ISO, and we talked generally about EPA rules for a few minutes, and that brief discussion may possibly have included a mention of the "safety valve".

b. Please describe any "safety valve" proposals considered or under consideration by FERC or any other federal agency that would allow utilities

to operate under the EPA power sector regulations until reliability concerns have been mitigated.
Answer: I believe that the "safety valve" proposal is directed to EPA and not FERC.

c. Please cite any provision of any of EPA's proposed power sector regulations upon which a utility could rely in knowing an extension of the regulatory or statutory compliance period is available as a "safety valve" in order to ensure reliability.
Answer: I do not know if the EPA has such a provision in its regulations, but perhaps an individual at the EPA would know the answer to this question.

d. Wouldn't it be more prudent to extend the compliance deadlines of the EPA power sector rules before an emergency occurs, rather than hoping that emergency waiver authority can stave off a reliability crisis after the fact?
Answer: Any decision about the compliance deadlines of the EPA rules would be within the authority of EPA and not FERC.

Question 12. EPA's proposed Utility MACT Rule was published in the *Federal Register* on May 3, 2011. The preamble of the proposed rule expressly provides that:

"Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained"

This statement clearly contemplates that reliability issues should be identified and addressed simultaneously with the rulemaking process to ensure these issues are resolved to the extent practicable prior to finalization of the rules. Yet, according to the information and answers you provided to the Committee, communications between FERC staff and EPA regarding the potential impacts of EPA rules on electric reliability ceased after May 3, 2011 and "have not been ongoing."

a. Were you aware that EPA's proposed Utility MACT Rule expressly calls upon FERC and DOE to cooperate in assuring that reliability is maintained and that this coordination is to occur before the rule becomes final?
Answer: Yes.

b. If so, how do you reconcile the fact that communications between FERC and EPA apparently ended on May 3, 2011, the same day as EPA's proposed rule was published but well before the rule will become final?
Answer: I cannot reconcile these facts.

c. If EPA and FERC are continuing to coordinate, please outline the process by which the Commission and EPA are doing so to further evaluate the reliability impacts of EPA's power sector rules. Please specify the type of coordination *(e.g.,* staff level meetings, information sharing, etc.) and identify the specific reliability topics to be evaluated as part of your ongoing coordination.

Answer: As a Commissioner at FERC, I will be interested to receive the agency's official answer to this question. I do not have that answer at this time. Also, I am currently discussing the topic of additional process with my fellow Commissioners at this time. Thus, I do not know what additional process will take place.

d. In the absence of any additional coordination with EPA, please describe the process the Commission intends to undertake to evaluate the cumulative impacts of EPA's power sector regulations on the reliability of the electric grid. Please include the following information:

i. the scope of the process;
ii. the timeline for carrying out the process;
iii. the participation of other agencies, entities, and officials *(e.g.,* federal agencies, NERC, RTOs, state public utility commissions, industry); and
iv. plans for updated or new reliability studies or assessments, including joint studies with NERC or regional and sub-regional studies overseen by FERC.

Answer: As a Commissioner at FERC, I will be interested to receive the agency's official answer to this question. I do not have that answer at this time. Also, I am currently discussing the topic of additional process with my fellow Commissioners at this time. Thus, I do not know what additional process will take place.

Question 13. FERC staff completed and presented to EPA a PowerPoint presentation entitled "Potential Retirement of Coal Fired Generation and its Effect on System Reliability (Preliminary Results)" (see attached). Slide 29 of this presentation is entitled "Next Steps" and details several FERC staff recommendations, including directing industry to "openly assess the reliability and adequacy impacts of retirement of at risk units." FERC staff then identified a list of factors that any such assessments should consider, including frequency response, voltage profile and bulk power system loadings, stability, loss of load probability calculations, and deliverability of resources through planning studies. The slide also provides that FERC staff will continue to "improve screening methodology with industry cooperation" and "conduct reliability studies."

a. Please describe whether any of the identified "Next Steps" of Slide 29 have been completed by FERC staff or are in the process of being completed. Please provide any related documentation or materials.

Answer: As a Commissioner at FERC, I will be interested to receive the agency's official answer to this question. I do not have that answer at this time.

b. If no "Next Steps" have been completed, please detail the decision-making process resulting in the conclusion that the recommendations of FERC staff should not be followed.
Answer: As a Commissioner at FERC, I will be interested to receive the agency's official answer to this question. I do not have that answer at this time.

Question 14. You have emphasized the importance of regional and local planning entities, including state public utility commissions, to ensuring reliability, particularly at the local level. The State of South Carolina recently petitioned FERC requesting the Commission to convene a joint board with state regulators to study the potential impacts of EP A's power sector rules on reliability.

a. Do you believe this would be a worthwhile federal-state partnership that could help identify and mitigate potential reliability problems? If not, why not? If you agree such a partnership is worthwhile, do you plan to establish a joint board with South Carolina state regulators? With other states?
Answer: The South Carolina petition is currently pending before the Commission, and for that reason, at this time it may make sense for me to discuss this matter with my fellow Commissioners first.

b. When do you plan to respond to South Carolina?
Answer: The Chairman calls matters to a vote. I plan to vote on this matter when given the opportunity to vote.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF THE COMMISSIONER

October 18, 2011

The Honorable Ed Whitfield, Chairman
Subcommittee on Energy and Power
House of Representatives
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515-6115

Dear Representative Whitfield:

Thank you for the opportunity to appear before the Subcommittee on Energy and Power (Subcommittee) on September 14, 2011. I also appreciate the opportunity to respond to your additional questions of October 4, 2011.

Reliability compliance and environmental compliance are critical matters for the nation and its consumers. Under Section 215 of the Federal Power Act, the Commission is statutorily mandated to ensure reliable wholesale electric service is provided at just and reasonable rates. Reliable service of electricity is essential to the health, welfare and safety of the American people and necessary to serve our economy.

Thus, it is not surprising that there has been much debate over how the Environmental Protection Agency's (EPA) proposed regulations may impact the nation's electric grid. As stated in my testimony before the Subcommittee, the regulated entities (whether the Independent System Operator or Regional Transmission Organization (ISO/RTO) or local utilities) are in the best position to evaluate the cumulative impact of the EPA's proposed regulations on reliability and what needs to be done to ensure that compliance with those rules will not hinder the reliable operation of the transmission grid.

The Southwest Power Pool's (SPP) letter to the EPA Administrator dated September 20, 2011, is an example of the role the regulated entities can play in evaluating the impact of the rules on reliability. The SPP sent its letter in its capacity as a Commission-approved Regional Transmission Organization and as a Regional Entity. Once the regulated entities demonstrate the potential effect of the new rules on reliability, as done by the SPP, the result of their analyses must be considered in the context of the EPA's proposed regulations. The record on which the EPA bases its regulations should consider these important facts and analyses. The technical conference the Commission has announced in FERC Docket No. AD12-1-000 will provide another forum for regulated entities to address issues that may arise in the course of compliance with EPA regulations.

The electric industry recognizes its obligation to comply with both environmental regulations and FERC-approved reliability standards and to plan their systems to reliably serve consumers while satisfying environmental requirements. As demonstrated by the SPP letter mentioned above, the regions are already analyzing the potential impact of the proposed environmental regulations. I do not believe that a generic review of the EPA's proposed regulations would disclose identical impacts on all regions. Planning decisions are typically made at the local or state level and their processes should play a role in compliance with the EPA's proposed regulations. The regulated entity, therefore, is the appropriate entity to do this review.

Regulated entities must have adequate time to plan their systems to comply with the rules that the EPA promulgates and the Commission-approved reliability standards. As the SPP discusses, inadequate time to comply with the EPA's proposed regulations may result in the users, owners and operators of the bulk-electric system being compelled by their government to choose between compliance with environmental laws or with Commission-approved reliability standards, and then face a penalty from one of the agencies. Regulated entities should not be put in the position of having to elect which agency's penalty they would rather face.

Also, I continue to support the development of a properly designed "reliability safety valve" mechanism. Any "reliability safety valve" mechanism that is adopted should be designed to permit case-specific extensions of time for environmental compliance by a generator that is critical to the reliable operation of the grid. However, I envision any "reliability safety valve" mechanism as a tool to use after regulated entities are first given adequate time to comply with the EPA's proposed regulations. Providing regulated entities adequate time to comply with the EPA's proposed regulations will enable them to plan changes to their systems in a way that should minimize instances in which a "reliability safety valve" would be needed. For example, the need for a "reliability safety valve" may be high if an entity only has one year to comply with the EPA's proposed regulations, but such need might diminish if the entity has three or five years to comply and makes changes to its system during those years to fill the void that may be left if a critical unit is retired. Yet, notwithstanding an adequate compliance period, there still may be generators that are not in compliance with an environmental requirement but remain critical for the reliability of the grid. Given the importance of the reliability of the grid, we should adopt a "belt and suspenders" level of protection that allows for adequate compliance time and the failsafe of a "reliability safety valve" for critical units. An adequate compliance period coupled with a "reliability safety valve" for critical units would best ensure that regulated entities are not faced with a Hobson's choice that neither serves consumers nor results in good government.

My answers to your specific questions are attached. I thank you for the opportunity to express my thoughts on these important issues. I hope the foregoing discussion has been responsive to your questions, and I invite any further questions or comments on this critical matter.

Sincerely,

Marc Spitzer
Commissioner
Federal Energy Regulatory Commission

cc: The Honorable Bobby Rush, Ranking Member
Subcommittee on Energy and Power

Attachment

Commissioner Marc Spitzer's Responses
To Questions of the
Subcommittee on Energy and Power
Dated October 4, 2011

The Honorable Ed Whitfield

1. What are the procedures to ensure that Commissioners are informed about the activity of FERC staff related to how EPA's power sector rules may impact reliability and prices? If a Commissioner has questions for FERC staff, how does he or she obtain an answer?

Answer: I have regular one-on-one meetings with the Chairman and the other Commissioners. I also meet regularly with the directors of each of the Commission's program offices, including the Office of Electric Reliability. If I have questions regarding a certain topic, I am free to contact the office directors or their staff at any time.

2. Please provide the date of when you first received a copy of the Commission's "informal" study analyzing the reliability impacts of EPA's power sector rules.

Answer: I believe it was in the Fall of 2010.

3. Do you believe the study completed by FERC staff was either "informal" or "irrelevant?" If so, please provide each and every reason why you consider FERC's study to have been "informal" and/or "irrelevant."

Answer: I agree that the study completed by FERC staff was "informal," but I disagree that the study was "irrelevant." As discussed at the September 14th hearing, the study completed by FERC staff was "informal" because it was a general analysis based on broad assumptions regarding the potential scope of the EPA's regulations and future planning needs. The study was not comprehensive; it did not address all of the numerous issues impacting power supply and/or electric reliability. Moreover, planning for reliability is an inherently localized, iterative process. Accordingly, local planners are in the best position to evaluate the cumulative impact of the EPA's proposed regulations on reliability and what needs to be done to ensure that compliance with those rules will not hinder the reliable operation of the transmission grid. Despite these limitations, however, the study completed by FERC staff is not "irrelevant" in that it provides information regarding general power supply issues based on a certain set of assumptions (albeit outdated assumptions) regarding the scope of the EPA's regulations. Although the study is not "irrelevant," I would concede that it is not dispositive as to the impact of the EPA's rules, for the reasons described above.

4. Do you believe the Commission should "formalize" its "informal" assessment of how EPA's power sector rules might impact reliability and prices?

Answer: I do not believe it is necessary to formalize the informal study completed by FERC staff. As stated above, transmission planning is inherently a localized, iterative process. By its very nature, any formal assessment done on a national level would be outdated as system conditions evolve and assumptions are updated.

5. Have you requested FERC staff to cease work on evaluating how EPA's power sector rules might impact reliability and cost/price issues? If not, what work by each FERC division is continuing or ongoing?

Answer: I have not requested FERC staff to cease work on evaluating how EPA's power sector rules might impact reliability and cost/price issues. I have no further information to add to the response provided by Chairman Wellinghoff regarding the continuing or ongoing work of FERC staff.

6. Please provide any documents from the following FERC offices that discuss, involve, or consider EPA regulations related to prices or reliability regarding electricity, or to prices or reliability regarding natural gas: Office of Enforcement; Office of Energy Policy and Innovation; Office of Energy Projects; Office of Electric Reliability; Office of Energy Market Regulation; Office of External Affairs; Office of General Counsel; Office of the Executive Director; and Office of the Secretary.

Answer: I have no documents that have not previously been provided to the Subcommittee.

7. If the type of work that FERC staff completed is "irrelevant," as has been suggested, then would it not be true that the same type of work being completed by NERC also is irrelevant?

Answer: As stated above, I do not believe the study completed by FERC staff is irrelevant. I think a study performed by NERC would be a useful source of information as to electric reliability.

8. Please compare the analytical work done in the FERC "informal" study to the analytical work completed by EPA in its reliability modeling.

> **a. For each component of the work done by EPA in its reliability modeling, where is that component reflected in the work done by FERC? And vice versa?**
> **b. Does this demonstrate that EPA reviewed fewer issues than FERC? If so, then isn't the analytical work done by EPA even less formal than the allegedly "informal" work completed by FERC staff? If not, please provide each and every reason why the EPA study is superior to the FERC assessment.**

Answer: I have no further information to add to the response provided by Chairman Wellinghoff.

9. Please describe the Commission's efforts on the following reliability issues: (1) cybersecurity; (2) standards; (3) event analysis; (4) investigations; and (5) penalties. Please contrast these efforts with the Commission's efforts on how EPA's power sector rules might impact reliability.

Answer: I have no further information to add to the response provided by Chairman Wellinghoff.

10. Does your Office of Enforcement, Division of Market Oversight, monitor issues that have an impact on natural gas and electricity prices? If so, why not monitor impacts that EPA's regulations might have on the cost of natural gas and electricity?

Answer: Chairman Wellinghoff has described the duties of FERC's Office of Enforcement, Division of Market Oversight in his response. However, I would add that issues regarding energy supply are complex and involve a variety of factors. FERC should be attentive to the impact of forces, market or otherwise, on wholesale power prices and rates charged to consumers.

11. During the hearing, there were several references to a reliability "safety valve" as a way to mitigate reliability concerns by permitting a waiver or case-specific extension to avoid reliability threats and potential emergencies.

a. Please document all discussions FERC has had regarding such a "safety valve" approach with representatives of EPA, any RTO or ISO, or state public service commissions.
b. Please describe any "safety valve" proposals considered or under consideration by FERC or any other federal agency that would allow utilities to operate under the EPA power sector regulations until reliability concerns have been mitigated.
c. Please cite any provision of any of EPA's proposed power sector regulations upon which a utility could rely in knowing an extension of the regulatory or statutory compliance period is available as a "safety valve" in order to ensure reliability.
d. Wouldn't it be more prudent to extend the compliance deadlines of the EPA power sector rules before an emergency occurs, rather than hoping that emergency waiver authority can stave off a reliability crisis after the fact?

Answer: I have no further documentation with regard to the response provided by Chairman Wellinghoff. Any decision regarding compliance deadlines is within the authority of EPA and not FERC. However, I would advocate for use of a properly designed "reliability safety valve" mechanism. Any "reliability safety valve" mechanism that is adopted should be designed to permit case-specific extensions of time for environmental compliance by a generator that is critical to the reliable operation of the grid. I envision any "reliability safety valve" mechanism as a tool to use after regulated entities are first given adequate time to comply with the EPA's proposed regulations. Providing regulated entities adequate time to comply with the EPA's proposed regulations will enable them to plan changes to their systems in a way that should minimize instances in which a "reliability safety valve" would be needed. For example, the need for a "reliability safety valve" may be high if an entity only has one year to comply with the EPA's proposed regulations, but such need might diminish if the entity has three or five years to comply and makes changes to its system during those years to fill the void that may be left if a critical unit is retired. Yet, notwithstanding an adequate compliance period, there still may be generators that are not in compliance with an environmental requirement but remain critical for the reliability of the grid. Given the importance of the reliability of the grid, we should adopt a "belt and suspenders" level of protection that allows for adequate compliance time and the failsafe of a "reliability safety valve" for critical units. An adequate compliance period coupled with a "reliability safety valve" for critical units would best ensure that regulated entities are not faced with a Hobson's choice that neither serves consumers nor results in good government.

12. EPA's proposed Utility MACT Rule was published in the *Federal Register* on May 3, 2011. The preamble of the proposed rule expressly provides that:

> **"Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained. "**

This statement clearly contemplates that reliability issues should be identified and addressed simultaneously with the rulemaking process to ensure these issues are resolved to the extent practicable prior to finalization of the rules. Yet, according to the information and answers provided to the Committee by FERC, communications between FERC staff and EPA regarding the potential impacts of EPA rules on electric reliability ceased after May 3,2011 and "have not been ongoing."

a. Were you aware that EPA's proposed Utility MACT Rule expressly calls upon FERC and DOE to cooperate in assuring that reliability is maintained and that this coordination is to occur before the rule becomes final?
b. If so, how do you reconcile the fact that communications between FERC and EPA apparently ended on May 3, 2011, the same day as EPA's proposed rule was published but well before the rule will become final?
c. If EPA and FERC are continuing to coordinate, please outline the process by which the Commission and EPA are doing so to further evaluate the reliability impacts of EPA's power sector rules. Please specify the type of coordination *(e.g.,* staff level meetings, information sharing, etc.) and identify the specific reliability topics to be evaluated as part of this ongoing coordination.
d. In the absence of any additional coordination with EPA, please describe the process the Commission intends to undertake to evaluate the cumulative impacts of EPA's power sector regulations on the reliability of the electric grid. Please include the following information:

i. the scope of the process;
ii. the time line for carrying out the process;

> **iii. the participation of other agencies, entities, and officials *(e.g.,* federal agencies, NERC, RTOs, state public utility commissions, industry); and**
> **iv. plans for updated or new reliability studies or assessments, including joint studies with NERC or regional and sub-regional studies overseen by FERC.**

<u>*Answer:*</u> I have no further information to add to the response provided by Chairman Wellinghoff. Once the regulated entities demonstrate the potential effect of the new rules on reliability, the result of their analyses should be considered in the context of the EPA's proposed regulations. The record on which the EPA bases its regulations should consider these important facts and analyses. The technical conference the Commission has announced in FERC Docket No. AD12-1-000 will provide another forum for regulated entities to address issues that may arise in the course of compliance with EPA regulations.

13. FERC staff completed and presented to EPA a PowerPoint presentation entitled "Potential Retirement of Coal Fired Generation and its Effect on System Reliability (Preliminary Results)" (see attached). Slide 29 of this presentation is entitled "Next Steps" and details several FERC staff recommendations, including directing industry to "openly assess the reliability and adequacy impacts of retirement of at risk units." FERC staff then identified a list of factors that any such assessments should consider, including frequency response, voltage profile and bulk power system loadings, stability, loss of load probability calculations, and deliverability of resources through planning studies. The slide also provides that FERC staff will continue to "improve screening methodology with industry cooperation" and "conduct reliability studies."

> **a. Please describe whether any of the identified "Next Steps" of Slide 29 have been completed by FERC staff or are in the process of being completed. Please provide any related documentation or materials.**
> **b. If no "Next Steps" have been completed, please detail the decision-making process resulting in the conclusion that the recommendations of FERC staff should not be followed.**

<u>*Answer:*</u> I have no further information to add to the response provided by Chairman Wellinghoff.

14. All the Commissioners have emphasized the importance of regional and local planning entities, including state public utility commissions, to ensuring reliability, particularly at the local level. The State of South Carolina recently

petitioned FERC requesting the Commission to convene a joint board with state regulators to study the potential impacts of EPA's power sector rules on reliability.

> **a. Do you believe this would be a worthwhile federal-state partnership that could help identify and mitigate potential reliability problems? If not, why not? If you agree such a partnership is worthwhile, do you believe FERC should establish a joint board with South Carolina state regulators? With other states?**

Answer: FERC should issue a notice on the petition filed by the Public Service Commission of South Carolina and South Carolina Office of Regulatory Staff to solicit public filings on the issues raised in the petition. Without prejudging how the Commission would ultimately rule on the issues raised in the petition, the issues are important not only for South Carolina but also for a number of other states as well. I note that the Mississippi Public Service Commission, the South Dakota Public Utilities Commission, the Public Service Commission of West Virginia, and the North Carolina Utilities Commission have filed responses to the petition with FERC. Any action the FERC may take on the petition should be informed by public filings.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

OFFICE OF THE COMMISSIONER

October 18, 2011

The Honorable Ed Whitfield, Chairman
Subcommittee on Energy and Power
Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Representative Whitfield:

Thank you for the opportunity to appear before the Subcommittee on Energy and Power on September 14, 2011. Enclosed, please find my responses to the Additional Questions for the Record of October 4, 2011. Please do not hesitate to contact me if you have any further questions or would like to discuss these responses.

Sincerely,

John R. Norris

<u>Responses of Commissioner John R. Norris to Additional Questions for the Record from the Honorable Ed Whitfield</u>

1. **What are the procedures to ensure that Commissioners are informed about the activity of FERC staff related to how EPA's power sector rules may impact reliability and prices? If a Commissioner has questions for FERC staff, how does he or she obtain an answer?**

<u>Answer:</u> I have regular meetings with senior staff during which I am informed of significant upcoming issues. Aside from these regular meetings, Commission staff is always available to discuss important issues and provide needed information.

2. **Please provide the date of when you first received a copy of the Commission's "informal" study analyzing the reliability impacts of EPA's power sector rules.**

<u>Answer:</u> I received a briefing from Commission staff on its study in October 2010. I received Commission staff's entire analysis on May 27, 2011.

3. **Do you believe the study completed by FERC staff was either "informal" or "irrelevant?" If so, please provide each and every reason why you consider FERC's study to have been "informal" and/or "irrelevant."**

<u>Answer:</u> I believe that the study completed by FERC staff was informal, as it was not part of any formal Commission process and did not involve or relate to any formal action by the Commission. However, I do not believe the study is irrelevant. The study provided a projection of the amount of capacity that could retire in response to new EPA air and water quality regulations, based on assumptions regarding the requirements EPA might propose or adopt. While the study provided a useful data point for consideration at the time it was produced, many of the assumptions it relied on have since become outdated as EPA's regulatory process has moved forward.

4. **Do you believe the Commission should "formalize" its "informal" assessment of how EPA's power sector rules might impact reliability and prices?**

<u>Answer:</u> No, I do not believe it is necessary for the Commission to formalize its assessment of how EPA's power sector rules might impact reliability and prices. Numerous studies by multiple entities have and continue to perform such analyses. Therefore, I do not believe an additional Commission-conducted macro-level analysis would be particularly probative.

5. **Have you requested FERC staff to cease work on evaluating how EPA's power sector rules might impact reliability and cost/price issues? If not, what work by each FERC division is continuing or ongoing?**

<u>Answer:</u> No, I have not requested that FERC staff cease work on evaluating how EPA's power sector rules might impact reliability and cost/price issues. However, FERC staff work under the

direction of the Chairman. As such, any questions regarding the work of FERC staff are appropriately referred to the Chairman.

6. **Please provide any documents from the following FERC offices that discuss, involve, or consider EPA regulations related to prices or reliability regarding electricity, or to prices or reliability regarding natural gas: Office of Enforcement; Office of Energy Policy and Innovation; Office of Energy Projects; Office of Electric Reliability; Office of Energy Market Regulation; Office of External Affairs; Office of General Counsel; Office of the Executive Director; and Office of the Secretary.**

Answer: My understanding is that all documents requested have previously been provided.

7. **If the type of work that FERC staff completed is "irrelevant," as has been suggested, then would it not be true that the same type of work being completed by NERC also is irrelevant?**

Answer: As I stated in response to question 3, I do not believe the informal analysis FERC staff conducted in October 2010 is irrelevant. For the same reasons, I do not believe that similar work conducted by NERC has been or will be irrelevant. This work will provide updated data to help inform how we go forward, using a variety of available tools, to address any local or regional reliability issues that may arise as the industry achieves compliance with new EPA regulations.

8. **Please compare the analytical work done in the FERC "informal" study to the analytical work completed by EP A in its reliability modeling.**

    a. **For each component of the work done by EPA in its reliability modeling, where is that component reflected in the work done by FERC? And vice versa?**

    b. **Does this demonstrate that EPA reviewed fewer issues than FERC? If so, then isn't the analytical work done by EPA even less formal than the allegedly "informal" work completed by FERC staff? If not, please provide each and every reason why the EPA study is superior to the FERC assessment.**

Answer: I am not aware of any analysis that has been done to compare the FERC analysis to the work EPA completed in its reliability modeling. A study of this magnitude would have to be conducted by FERC staff, who work at the direction of the Chairman. I do not have the necessary resources to complete this level of detailed analysis.

9. **Please describe the Commission's efforts on the following reliability issues: (1) cybersecurity; (2) standards; (3) event analysis; (4) investigations; and (5) penalties. Please contrast these efforts with the Commission's efforts on how EPA's power sector rules might impact reliability.**

Answer: Each of these efforts relate directly to FERC's primary responsibility, under section 215 of the Federal Power Act, to establish mandatory and enforceable reliability standards for the bulk power system. 16 U.S.C. § 824o. Under the paradigm established by Congress in section 215, those standards are developed by the Electric Reliability Organization, which has established processes for developing the standards through industry stakeholder groups. FERC does not write the standards itself, but instead either approves the standards as "just, reasonable, not unduly discriminatory, and in the public interest," or remands the standards to the Electric Reliability Organization for further consideration if it cannot make such a finding. See 16 U.S.C. §§ 824o(d)(2) and (d)(4). FERC may order the Electric Reliability Organization to develop and submit a new or modified standard to address a specific reliability matter, but cannot write a standard itself to address that matter. 16 U.S.C. § 824o(d)(5). In addition, under section 215, both the Electric Reliability Organization and FERC have the authority to impose a penalty on a user, owner or operator of the bulk power system if, after notice and an opportunity for a hearing, it finds that the entity has violated a Commission-approved reliability standard. See 16 U.S.C. § 824o(e).

Unlike our FPA section 215 authority, FERC does not have a statutory mandate to oversee EPA regulations, or to direct modifications or enforce compliance with those regulations. This is not to suggest, however, that it is not important for the Commission to monitor EPA regulatory efforts and provide input to EPA when requested, as Commission staff has done. These less formal efforts (which the Commission and its staff undertake in many areas) are prudent steps to ensure that the Commission is well informed of issues impacting the industries we regulate. These efforts are also important to help the Commission monitor whether the tools and authorities within our jurisdiction that can be utilized to manage the implementation of the rules are effective, or whether changes are needed to ensure that compliance with EPA's rules is achieved in the most efficient way possible.

10. Does your Office of Enforcement, Division of Market Oversight, monitor issues that have an impact on natural gas and electricity prices? If so, why not monitor impacts that EPA's regulations might have on the cost of natural gas and electricity?

Answer: The Division of Energy Market Oversight does monitor issues that have an impact on natural gas and electricity prices. I see no reason why the Division of Energy Market Oversight should not monitor the broad market impacts that EPA's regulations might have on the cost of natural gas and electricity.

11. During the hearing, there were several references to a reliability "safety valve" as a way to mitigate reliability concerns by permitting a waiver or case-specific extension to avoid reliability threats and potential emergencies.

a. Please document all discussions FERC has had regarding such a "safety valve" approach with representatives of EPA, any RTO or ISO, or state public service commissions.

Answer: While I have not personally had any such discussions, my staff attended an August 10, 2011 briefing held by PJM staff that described PJM's comments (and similar comments filed jointly by several RTOs) on EPA's proposed hazardous air pollutants rule. In those comments, PJM and the other RTOs (Electric Reliability Council of Texas, Midwest Independent Transmission System Operator, Inc., New York Independent System Operator, and Southwest

Power Pool) propose a "safety valve" to address any local reliability issues that may arise under a final hazardous air pollutants rule.

b. Please describe any "safety valve" proposals considered or under consideration by FERC or any other federal agency that would allow utilities to operate under the EPA power sector regulations until reliability concerns have been mitigated.

Answer: I am not aware of any "safety valve" proposals before FERC. As noted in response to question 11.a, however, I am aware that several of the RTO/ISOs have submitted a proposal to EPA that would provide for additional, targeted compliance flexibility in a situation where the RTO/ISO determines that a specific generating unit seeking to retire is needed for reliability, and where additional time is needed to implement measures that would mitigate reliability concerns before allowing the unit to retire.

c. Please cite any provision of any of EPA's proposed power sector regulations upon which a utility could rely in knowing an extension of the regulatory or statutory compliance period is available as a "safety valve" in order to ensure reliability.

Answer: Because the proposed and final regulations were developed by EPA, that agency is in the best position to answer this question. However, it is my understanding that EPA's proposed rules and the Clean Air Act allow for some compliance flexibility where necessary. For example, my understanding is that while EPA's proposed MACT rule requires all existing utilities to come into compliance by 2015, EPA provides for a one-year extension for sources which will be considered on a case-by-case basis. In addition, it is my understanding that the transport rule (CSAPR) is implemented over an extended period of time, with the first phase of compliance for annual NOx and SO2 requirements beginning on January 1, 2012, the ozone-season NOx requirements beginning on May 1, 2012, and the second phase of S02 reduction requirements beginning on January 1, 2014.

d. Wouldn't it be more prudent to extend the compliance deadlines of the EPA power sector rules before an emergency occurs, rather than hoping that emergency waiver authority can stave off a reliability crisis after the fact?

Answer: FERC does not have authority to administer the Clean Air Act. As a result, I am not in a position to make a judgment regarding the possible extension of compliance deadlines.

12. EPA's proposed Utility MACT Rule was published in the *Federal Register* on May 3, 2011. The preamble of the proposed rule expressly provides that:

> **"Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained."**

This statement clearly contemplates that reliability issues should be identified and addressed simultaneously with the rulemaking process to ensure these issues are resolved to the extent practicable prior to finalization of the rules. Yet, according to the information and answers provided to the Committee by FERC, communications between FERC staff and EPA regarding the potential impacts of EPA rules on electric reliability ceased after May 3, 2011 and "have not been ongoing."

a. **Were you aware that EPA's proposed Utility MACT Rule expressly calls upon FERC and DOE to cooperate in assuring that reliability is maintained and that this coordination is to occur before the rule becomes final?**

Answer: My understanding is that Commission staff, under the direction of the Chairman, periodically met with EPA to discuss the reliability implications of the EPA rules and identify authorities and policy tools regarding electric reliability. Over the past year, I also met with EPA Assistant Administrator Gina McCarthy to discuss the status and content of the proposed EPA rules. I am ready and willing to cooperate with EPA in any way needed as it finalizes its proposed rules and as EPA and the industry work to achieve compliance with those rules.

b. **If so, how do you reconcile the fact that communications between FERC and EPA apparently ended on May 3, 2011, the same day as EPA's proposed rule was published but well before the rule will become final?**

Answer: Given that Commission staff work at the direction of the Chairman, I defer to his response.

c. **If EPA and FERC are continuing to coordinate, please outline the process by which the Commission and EPA are doing so to further evaluate the reliability impacts of EPA's power sector rules. Please specify the type of coordination *(e.g.,* staff level meetings, information sharing, etc.) and identify the specific reliability topics to be evaluated as part of this ongoing coordination.**

Answer: Given that Commission staff work at the direction of the Chairman, I defer to his response.

d. **In the absence of any additional coordination with EPA, please describe the process the Commission intends to undertake to evaluate the cumulative impacts of EPA's power sector regulations on the reliability of the electric grid. Please include the following information:**

   i. **the scope of the process;**
   ii. **the timeline for carrying out the process;**
   iii. **the participation of other agencies, entities, and officials *(e.g.,* federal agencies, NERC, RTOs, state public utility commissions, industry); and**

iv. plans for updated or new reliability studies or assessments, including joint studies with NERC or regional and sub-regional studies overseen by FERC.

Answer: I do not believe an additional macro-level analysis regarding EPA's proposed regulations would be particularly probative. Based on the available information reviewed to date, it appears that any reliability concerns that emerge will largely be local and related to specific generator retirements, which cannot be identified until the EPA rules are finalized and utilities and other generation owners are able to make their own assessments of the continued economic viability of their assets. Once the EPA rules are final and generation owners have the opportunity to make their own business decisions as to whether to continue to operate, any potential local reliability concerns can be adequately studied and addressed using the tools available to industry and regulators. Additionally, the Commission recently announced a technical conference to discuss policy issues related to the reliability of the bulk-power system. The technical conference will also discuss processes used by planning authorities and other entities to identify reliability concerns that may arise in the course of compliance with EPA regulations, and the tools and processes (including tariffs and market rules) available to address any identified reliability concerns. Finally, I note that NERC is in the process of updating its annual long-term reliability assessment, which may provide additional helpful information regarding the potential impact of EPA regulations.

13. FERC staff completed and presented to EPA a PowerPoint presentation entitled "Potential Retirement of Coal Fired Generation and its Effect on System Reliability (Preliminary Results)" (see attached). Slide 29 of this presentation is entitled "Next Steps" and details several FERC staff recommendations, including directing industry to "openly assess the reliability and adequacy impacts of retirement of at risk units." FERC staff then identified a list of factors that any such assessments should consider, including frequency response, voltage profile and bulk power system loadings, stability, loss of load probability calculations, and deliverability of resources through planning studies. The slide also provides that FERC staff will continue to "improve screening methodology with industry cooperation" and "conduct reliability studies."

a. Please describe whether any of the identified "Next Steps" of Slide 29 have been completed by FERC staff or are in the process of being completed. Please provide any related documentation or materials.

b. If no "Next Steps" have been completed, please detail the decision-making process resulting in the conclusion that the recommendations of FERC staff should not be followed.

Answer: FERC staff works at the direction of the Chairman, and I do not have personal knowledge of the next steps FERC staff has taken or is in the process of taking.

14. All the Commissioners have emphasized the importance of regional and local planning entities, including state public utility commissions, to ensuring reliability, particularly at the local level. The State of South Carolina recently petitioned FERC requesting the

Commission to convene a joint board with state regulators to study the potential impacts of EPA's power sector rules on reliability.

a. **Do you believe this would be a worthwhile federal-state partnership that could help identify and mitigate potential reliability problems? If not, why not? If you agree such a partnership is worthwhile, do you believe FERC should establish a joint board with South Carolina state regulators? With other states?**

Answer: Because the petition from the State of South Carolina is currently pending before the Commission, it would be inappropriate for me to comment on its merits at this time.

October 18, 2011

The Honorable Ed Whitfield, Chairman
Subcommittee on Energy and Power
House of Representatives
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515-61115

Dear Representative Whitfield:

Thank you for your October 4, 2011 letter which contained additional questions for the hearing record on "The American Energy Initiative." Please find enclosed my responses to your questions. I want to thank you again for the opportunity to appear before the Subcommittee on Energy and Power on September 14, 2011 to discuss the potential impacts of the Environmental Protection Agency's regulations on electric reliability.

Sincerely,

Cheryl A. LaFleur

cc: The Honorable Bobby Rush, Ranking Member
Subcommittee on Energy and Power

Attachment

<u>The Honorable Ed Whitfield</u>

1. What are the procedures to ensure that Commissioners are informed about the activity of FERC staff related to how EPA's power sector rules may impact reliability and prices? If a Commissioner has questions for FERC staff, how does he or she obtain an answer?

Answer: To the extent that FERC staff is working on this (or any other) issue, they are always available to brief me and my staff upon request. In addition, I meet regularly with the directors of each of the Commission's program offices.

2. Please provide the date of when you first received a copy of the Commission's "informal" study analyzing the reliability impacts of EPA's power sector rules.

Answer: I believe that I was briefed on the study in late 2010.

3. Do you believe the study completed by FERC staff was either "informal" or "irrelevant?" If so, please provide each and every reason why you consider FERC's study to have been "informal" and/or "irrelevant."

Answer: As I noted in my previous testimony before this committee, I believe that there are two shortcomings associated with the FERC study. First, because the EPA regulations are not expected to affect our resource adequacy as a nation, any resulting reliability issues will likely surface on a relatively local basis and be tied to the retirement/retrofit decisions of individual units. Such decisions will ultimately depend on information that is unique to each unit and that "global" studies (like the FERC study) are unable to capture. Second, it is my understanding that the FERC study was performed based upon conservative assumptions regarding the ultimate content of the EPA rules, including in particular those with respect to cooling water, and that those assumptions have proven to be inaccurate in some respects.

4. Do you believe the Commission should "formalize" its "informal" assessment of how EPA's power sector rules might impact reliability and prices?

Answer: As I have indicated previously, I do not believe that another "global" study would be as useful as regional and local analyses of specific reliability issues. I think that it will be important to ensure that planning authorities have the ability to address these concerns as they arise. Consistent with that approach, the Commission is planning to hold a reliability conference on November 29-30 that will include presentations on and a discussion of the tools and processes (including tariffs and market rules) available to address any identified reliability concerns from the EPA regulations.

5. Have you requested FERC staff to cease work on evaluating how EPA's power sector rules might impact reliability and cost/price issues? If not, what work by each FERC division is continuing or ongoing?

Answer: As this question relates to the actions of FERC staff, I defer to the answer provided by Chairman Wellinghoff.

6. Please provide any documents from the following FERC offices that discuss, involve, or consider EPA regulations related to prices or reliability regarding electricity, or to prices or reliability regarding natural gas: Office of Enforcement; Office of Energy Policy and Innovation; Office of Energy Projects; Office of Electric Reliability; Office of Energy Market Regulation; Office of External Affairs; Office of General Counsel; Office of the Executive Director; and Office of the Secretary.

Answer: As this question relates to the actions of FERC staff, I defer to the answer provided by Chairman Wellinghoff. My office has previously provided all relevant documents in our possession.

7. If the type of work that FERC staff completed is "irrelevant," as has been suggested, then would it not be true that the same type of work being completed by NERC also is irrelevant?

Answer: See answer 3 above. I understand that NERC's revised study will be completed in November 2011.

8. Please compare the analytical work done in the FERC "informal" study to the analytical work completed by EPA in its reliability modeling.

a. For each component of the work done by EPA in its reliability modeling, where is that component reflected in the work done by FERC? And vice versa?

Answer: I am not aware of any detailed comparison of the two studies.

b. Does this demonstrate that EPA reviewed fewer issues than FERC? If so, then isn't the analytical work done by EPA even less formal than the allegedly "informal" work completed by FERC staff? If not, please provide each and every reason why the EPA study is superior to the FERC assessment.

Answer: See answer to 8.a above.

9. Please describe the Commission's efforts on the following reliability issues: (1) cybersecurity; (2) standards; (3) event analysis; (4) investigations; and (5) penalties. Please contrast these efforts with the Commission's efforts on how EPA's power sector rules might impact reliability.

Answer: As noted in the answer of Chairman Wellinghoff, the Commission has specific statutory authority to enact reliability standards and to enforce those standards as to retrospective violations through investigations and the imposition of penalties. Such standards may encompass cyber security. The Commission oversees event analyses that are conducted by NERC for specific reliability events. Such events may also prompt FERC reliability investigations. EPA's power sector rules have potential prospective impacts that are best addressed in the reliability planning activities of the planning authorities that are required and informed by FERC's reliability rules and Orders 890 and 1000.

10. Does your Office of Enforcement, Division of Market Oversight, monitor issues that have an impact on natural gas and electricity prices? If so, why not monitor impacts that EPA's regulations might have on the cost of natural gas and electricity?

Answer: As noted in the answer of Chairman Wellinghoff, the Division of Energy Market Oversight (DEMO) performs market oversight in an effort to detect fraud and market manipulation and to examine market conditions in the wholesale natural gas and electric power markets, as well as related energy and financial markets. To the extent that this question relates to the actions of FERC staff, I defer to the answer provided by Chairman Wellinghoff.

11. During the hearing, there were several references to a reliability "safety valve" as a way to mitigate reliability concerns by permitting a waiver or case-specific extension to avoid reliability threats and potential emergencies.

a. Please document all discussions FERC has had regarding such a "safety valve" approach with representatives of EPA, any RTO or ISO, or state public service commissions.

Answer: Neither I nor my staff have had any discussions with these groups concerning the "safety valve" approach. With respect to any discussions involving FERC Staff, I defer to the answer of Chairman Wellinghoff.

b. Please describe any "safety valve" proposals considered or under consideration by FERC or any other federal agency that would allow utilities

to operate under the EPA power sector regulations until reliability concerns have been mitigated.

Answer: I am aware of the August 4, 2011 proposal filed jointly by ERCOT, MISO, NYISO, PJM, and SPP to the EPA requesting the incorporation of a "reliability safety valve." The purpose of this safety valve proposal is to extend the time for compliance until alternative resources are in place to address the reliability issue created by the shutdown of a "reliability critical unit." On October 14, 2011, the same parties filed an update with the EPA that included specific rule language on how such a "safety valve" may be incorporated.

I received copies of these proposals, but they were actually filings with EPA, not with FERC.

c. Please cite any provision of any of EPA's proposed power sector regulations upon which a utility could rely in knowing an extension of the regulatory or statutory compliance period is available as a "safety valve" in order to ensure reliability.

Answer: I am not aware of such a specific provision in EPA's regulations. See answer to 11.b above. This is the type of issue that I expect may be addressed in FERC's reliability conference on November 29-30.

d. Wouldn't it be more prudent to extend the compliance deadlines of the EPA power sector rules before an emergency occurs, rather than hoping that emergency waiver authority can stave off a reliability crisis after the fact?

Answer: An extension for EPA compliance is within the jurisdiction of EPA, not FERC. As I explained in my testimony, I do believe that reliability issues that might be presented by the retirement decision of a specific unit should be addressed before the unit retires.

12. EPA's proposed Utility MACT Rule was published in the *Federal Register* on May 3, 2011. The preamble of the proposed rule expressly provides that:

> **"Between proposal and final, EPA will work with DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC that can be pursued to further ensure that the dual goals of substantially reducing the adverse public health impacts of power generation, as required by the CAA, while continuing to assure electric reliability is maintained. "**

This statement clearly contemplates that reliability issues should be identified and addressed simultaneously with the rulemaking process to ensure these issues are resolved to the extent practicable prior to finalization of the rules. Yet, according to the information and answers provided to the Committee by FERC, communications between FERC staff and EPA regarding the potential impacts of EPA rules on electric reliability ceased after May 3, 2011 and "have not been ongoing."

a. Were you aware that EPA's proposed Utility MACT Rule expressly calls upon FERC and DOE to cooperate in assuring that reliability is maintained and that this coordination is to occur before the rule becomes final?

Answer: I was not aware of this specific provision in the preamble. Coordination between FERC and the EPA has been described in the documents previously submitted to the Committee.

b. If so, how do you reconcile the fact that communications between FERC and EPA apparently ended on May 3, 2011, the same day as EPA's proposed rule was published but well before the rule will become final?

Answer: See my answer to 12.a above.

c. If EPA and FERC are continuing to coordinate, please outline the process by which the Commission and EPA are doing so to further evaluate the reliability impacts of EPA's power sector rules. Please specify the type of coordination *(e.g.,* staff level meetings, information sharing, etc.) and identify the specific reliability topics to be evaluated as part of this ongoing coordination.

Answer: Neither I nor my staff are currently engaged in discussions with the EPA. I do understand that the EPA is aware of and may participate in FERC's technical conference on November 29-30, 2011.

d. In the absence of any additional coordination with EPA, please describe the process the Commission intends to undertake to evaluate the cumulative impacts of EPA's power sector regulations on the reliability of the electric grid. Please include the following information:

> **i. the scope of the process;**
>
> **ii. the timeline for carrying out the process;**

iii. the participation of other agencies, entities, and officials *(e.g.,* federal agencies, NERC, RTOs, state public utility commissions, industry); and

iv. plans for updated or new reliability studies or assessments, including joint studies with NERC or regional and sub-regional studies overseen by FERC.

Answer: As noted previously, FERC has scheduled a reliability conference on November 29-30 which will include presentations on and a discussion of the tools and processes (including tariffs and market rules) available to address any identified reliability concerns from the EPA regulations.

13. FERC staff completed and presented to EPA a PowerPoint presentation entitled "Potential Retirement of Coal Fired Generation and its Effect on System Reliability (Preliminary Results)" (see attached). Slide 29 of this presentation is entitled "Next Steps" and details several FERC staff recommendations, including directing industry to "openly assess the reliability and adequacy impacts of retirement of at risk units." FERC staff then identified a list of factors that any such assessments should consider, including frequency response, voltage profile and bulk power system loadings, stability, loss of load probability calculations, and deliverability of resources through planning studies. The slide also provides that FERC staff will continue to "improve screening methodology with industry cooperation" and "conduct reliability studies."

a. Please describe whether any of the identified "Next Steps" of Slide 29 have been completed by FERC staff or are in the process of being completed. Please provide any related documentation or materials.

Answer: As this question relates to the actions of FERC staff, I defer to the answer provided by Chairman Wellinghoff.

b. If no "Next Steps" have been completed, please detail the decision-making process resulting in the conclusion that the recommendations of FERC staff should not be followed.

Answer: As this question relates to the actions of FERC staff, I defer to the answer provided by Chairman Wellinghoff.

14. All the Commissioners have emphasized the importance of regional and local planning entities, including state public utility commissions, to ensuring reliability, particularly at the local level. The State of South Carolina recently

petitioned FERC requesting the Commission to convene a joint board with state regulators to study the potential impacts of EPA's power sector rules on reliability.

a. Do you believe this would be a worthwhile federal-state partnership that could help identify and mitigate potential reliability problems? If not, why not? If you agree such a partnership is worthwhile, do you believe FERC should establish a joint board with South Carolina state regulators? With other states?

Answer: I believe that state, regional and federal authorities will need to communicate to ensure that any specific reliability issues are identified and that the tools and processes are in place to respond. However, because the South Carolina petition for a joint board is currently pending before the Commission, I am unable to comment on it.

ANALYSIS GROUP
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October 17, 2011

Congressman Ed Whitfield
Chairman, Subcommittee on Energy and Power
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, DC 20515-6115

Dear Chairman Whitfield:

Thank you very much for the invitation to testify before the Subcommittee on Energy and Power on September 14, 2011, at the hearing on "The American Energy Initiative."

I am writing to follow up on post-hearing questions posed by the Honorable Pete Olson in your letter dated October 4, 2011. My responses to each of his questions are on the following page.

Sincerely,

Susan Tierney

Susan F. Tierney, Ph.D.
Managing Principal
Analysis Group

Tierney response to Hearing Question from Congressman Olson
October 17, 2011

From Congressman Pete Olson:

In your testimony, you stated that "Congress has already provided the tools need to ensure that implementation of regulations designed to protect public health do not end us in a clash with other critical objectives, such as reliable electricity supply." .... "The Federal Power Act (Section 202(c)) gives the U.S. DOE the authority to override Clean Air Act control requirements in limited emergency circumstances where there is a finding that an electric emergency exists."....

I am concerned that this tool may be flawed in such a manner that its effectiveness is questionable. My understanding of the law is that if DOE issues an emergency order for an electricity generator to run, and compliance with the order would cause the generator to violate an established environmental permit limit, neither DOE nor EPA has authority to grant a waiver or immunity for such violation to the generator. Obviously, this circumstance could leave an electricity generator in a difficult position, having to choose between compliance with one federal mandate over another. My concern is that it jeopardizes electric reliability.

1. Can you explain your understanding of how Federal Power Act Section 202(c) authority interacts with consequent violations of federal, state or locally-established environmental limits?
    a. Is it your understanding that Section 202(c) gives DOE the authority to direct an electricity generator to violate Clean Air Act control requirements without exposing the generator to risks of civil, state or federal penalties or sanctions?
2. If DOE orders a generating unit to operate under Section 202(c), and doing so would result in the unit exceeding an environmental permit limit, or violating an environmental law or regulation, could DOE indemnify the unit operator from any and all environmental agency action or private citizen lawsuit liability?
3. I am concerned that an electricity generator might legally refuse to follow a DOE order to operate under section 202(c) by claiming that doing so would require it to violate another federal statute. Can you address this concern?

Tierney response to all three parts of Congressman Olson's questions:

As posed, these questions appear to be asking me for a legal opinion. Because I am not an attorney, I would not be able to provide you with such. I understand, in fact, that the courts have not yet been asked to render a decision on the specific questions you've asked to me, and therefore I'm not sure that there yet exists legal precedent to inform a response.

Without attempting to render a legal opinion, I understand that in a case where a proposed power plant retirement were not allowed to occur as a result of an electric system reliability issue, it may be possible for the parties (e.g., EPA, DOE and the power plant owner) to enter into a consent decree and amended operating permit that would allow the plant to operate strictly under reliability emergencies.